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DECISIONS

REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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

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

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ALBERTA ENERGY REGULATOR

Nexen Long Lake Pipeline Failure Environmental Protection Order
Environmental Protection Order – Pipeline Failure

On July 17, 2015, the AER issued an environmental protection order ("EPO") to Nexen Energy ULC ("Nexen"), after a failure on Nexen's pipeline licence number 54767 (the "Pipeline") which occurred on July 15, 2015. The Pipeline leaked approximately 5,000 cubic metres of emulsion consisting of 75 percent water and 25 percent bitumen into the surrounding right of way.

The AER was of the opinion that the release had caused, was causing or may cause an adverse impact on the environment, and that remedial work was required to mitigate the adverse effects. Therefore the AER issued the EPO.

The EPO directed Nexen to, among other things:

(a) Immediately contain the spill and prevent the further spread of the emulsion to any unaffected areas or waterbodies;

(b) Immediately identify and report on potentially affected parties that could be adversely affected by the release and to create a plan to notify such parties;

(c) Report to the director appointed for the purposes of issuing environmental protection orders under the *Environmental Protection and Enhancement Act* (the "Director") at 12:00 pm each day with a list of parties and times that they were notified until otherwise directed;

(d) Immediately control public access to the affected area;

(e) Immediately commence sampling at least once per 24 hour period, for hydrocarbons and chlorides in the affected waterbodies, wetlands and airshed until otherwise directed, and to provide the results of such samples by 12:00 pm each day;

(f) Immediately conduct an assessment of impacted wildlife, including fish, waterfowl and amphibians; and

(g) Report to the Director at the end of each day on the inventory of impacted wildlife until otherwise directed.

The EPO also required Nexen to submit by July 22, 2015:

(a) A detailed delineation and remediation plan outlining the steps to be taken to remediate the substance;

(b) A wildlife mitigation plan to prevent impacts and rehabilitate impacted wildlife; and

(c) For the humane euthanasia of impacted wildlife.

Under the terms of the EPO, Nexen is also required to submit a final report to the Director within 30 days of completion of all required work in the EPO, including verification that the work has met all standards and criteria as specified by the Director.

Issuance of Subsurface Order No. 1A Regarding the Montney-Lower Doig (Bulletin 2015-23)
Bulletin - Subsurface Order

The AER has issued Subsurface Order No. 1A, and rescinded the original Subsurface Order No. 1 regarding the Montney-Lower Doig. The new order expands the area set out in Subsurface Order No. 1, which was previously announced as part of Bulletin 2015-06. The terms and conditions of the Subsurface Order No. 1A remain the same as Subsurface Order No. 1 with two exceptions:

(a) Licensees must take drill-cutting samples at an interval frequency no greater than 20 metres within the Montney-Lower Doig geological zone; and

(b) The applicable area of the Subsurface Order No. 1A has expanded to include the original Subsurface Order No. 1, and an area to the southwest.

A map of the affected area, as well as a copy of the Subsurface Order No. 1A, can be found here.

ALBERTA UTILITIES COMMISSION

Direct Energy Regulated Services 2012-2016 Default Rate Tariff and Regulated Rate Tariff (Decision 2957-D01-2015)
Default Rate Tariff – Regulated Rate Tariff

Direct Energy Regulated Services ("DERS") applied for approval of a default rate tariff ("DRT") including a reasonable return on DRT service, and a regulated rate tariff ("RRT") for a five year period beginning on January 1, 2012 through December 31, 2016. DERS noted that it was applying for customer care and billing costs for 2015 and 2016 on an interim placeholder basis, as it would be engaging a new provider for that service after 2014.

Previous Decisions

DERS had previously applied to the AUC for approval of its 2012-2014 DRT and RRT under Proceeding 1454 through a negotiated settlement agreement ("NSA"), which the AUC rejected in Decision 2012-343, and under Proceeding 2406, which application the AUC determined was incomplete, and closed the proceeding.

The AUC made a number of directions to DERS in rejecting the NSA in Decision 2012-343. In this decision, the AUC determined that DERS had complied with directions 1, 2, and 4 through 7. The AUC held that DERS had partially complied with direction 3, which directed DERS to include specific amounts for its share award scheme in its DRT and RRT for 2012, 2013 and 2014. The AUC determined that DERS had included the proper amount for 2012, but had failed to update the amounts for 2013 and 2014. The AUC therefore ordered DERS to make the necessary corrections for the 2013 and 2014 share award scheme amounts in its compliance filing.

Revenue Requirement

DERS requested an inflation factor of 2.75 percent based on prior ATCO Gas applications, the Alberta Weekly Earnings and Alberta Consumer Price Index ("CPI"). The Consumers' Coalition of Alberta ("CCA") argued that, due to the major change in economic circumstances in Alberta since the original filing in 2012, the AUC should adopt a 0.1 inflation rate for 2015 and a 2.4 percent inflation rate for 2016, based on current external forecasts.

The AUC found that for the "Other Administration Costs" cost category, it was not reasonable for DERS to apply its requested inflation factor, as there were no direct labour costs in that category. The AUC directed DERS to apply an inflation rate of 0.1 percent for 2015 and 2.4 percent for 2016 to the "Other Administration Costs" cost category in its compliance filing.

The AUC accepted DERS' methodology for forecasting the remaining cost categories and inflation. The AUC determined that the prior ATCO Gas application was the result of a weighted average of the most up to date figures for Alberta Weekly Earnings data and CPI figures. The AUC calculated the forecast inflation rates for 2015 and 2016 to be 1.92 percent and 2.95 percent, respectively, and directed DERS to update the inflation rates accordingly.

Given the long delay since the initial application for the 2012-2014 test period, DERS submitted that the actual values for these test years should not be used for the sole purpose of simply reducing the applicant's revenue requirement. Rather, DERS submitted that the actual values be used as a tool for the AUC to validate the forecasts, noting that DERS has borne the risk on its revenue requirement for the test period, and that the revenue requirements must be approved on a prospective basis.

The Office of the Utilities Consumer Advocate ("UCA") submitted that the actual values for 2012 and 2013 reflect a pattern of material over-forecasting by DERS, and that the AUC should apply the actual results as the approved forecasts, citing AltaGas Utilities Inc. 2010-2012 general tariff application wherein the 2010 actual results were incorporated. The CCA agreed with the UCA's submissions, and requested reductions to reflect the actual financial data for the 2012-2014 period.

The AUC held that it would set the rates prospectively on the basis of forecast test years, but noted that it may approve the forecast revenue requirements, or approve the actual results for the 2012-2014 period, as well as the forecasts for 2015-2016 as the forecast revenue requirement.

The AUC cited its previous decisions where it applied principles of prospective ratemaking, but also required applicants to use the most up to date information available, including in some instances, actual results for certain test years. Therefore, with the exception of amounts already determined in earlier decisions, the AUC held that the 2012-2014 non-energy revenue requirements in this decision should be based on actual financial data. The AUC ordered DERS to adjust the requested revenue requirement for 2012-2014 to reflect actual amounts in its compliance filing.

With respect to forecast amounts for 2014, 2015 and 2016, the UCA submitted that the clear pattern of over-forecasting warranted reductions to the revenue requirements. The UCA recommended the application of actual data from 2012 and 2013 to update forecasts for site counts, which would result in reductions as follows:

(a) DRT forecasts:

(i) 2014 - $3.383 million;

(ii) 2015 - $3.354 million; and

(iii) 2016 - $3.368 million; and

(b) RRT forecasts:

(i) 2014 - $0.567million;

(ii) 2015 - $0.552 million; and

(iii) 2016 - $0.576 million.

The AUC partially agreed with the UCA's approach, holding that the use of a reasonable forecast does not obviate the use of a more accurate forecast if updated data becomes available. Therefore the AUC ordered DERS, in its compliance filing, to update its site counts forecasts for 2015 and 2016 based on the actual number of sites at the end of 2014.

With respect to the customer care and billing costs, DERS submitted that it had retained new services through a request for proposals following the expiry of its 10 year master services agreement with ATCO I-Tek, and would be outsourcing the customer care and billing functions to several suppliers, one of which was an affiliate.

The AUC found that a comprehensive request for proposals process was conducted, and that DERS adequately explored alternative options for customer care and billing.

Accordingly, the AUC accepted DERS' customer care and billing costs of $4.66 and $4.77 per site for 2015 and 2016 respectively, per site. The AUC directed DERS to reflect these amounts in its updated customer site counts for 2015 and 2016 in its compliance filing.

<u>Vendor Selection Costs</u>

DERS also requested approval to recover $300,000 for each of 2015 and 2016 under its DRT, and $75,000 for each of 2015 and 2016 under its RRT for vendor selection costs expended on the customer care and billing request for proposals, including consulting, legal and other costs.

The AUC disallowed the inclusion of the entirety of the vendor selection costs requested by DERS, noting that pricing had a minimal ranking in the request for proposal evaluation, and also noted that customers did receive some benefit through the comprehensive customer care and billing solution. Therefore, the AUC ordered DERS to reduce its vendor selection costs for each year from $750,000 to $356,250 in its compliance filing.

<u>Corporate Costs</u>

DERS requested an allocation of its corporate costs between the DRT and RRT of 80 and 20 percent respectively based on a 1.0 percent allocation for all corporate costs based on full-time equivalents for direct costs, and gross profit for indirect costs. DERS also submitted that its methodology, which also used gross margins was fair and reasonable, as these measures represented a proxy for the relative size of the business, and noted that the corporate costs allocated by DERS represented a smaller share of total revenue requirement compared with other regulated distribution utilities in Alberta.

The CCA argued that gross margins were inappropriate for several cost allocator items such as human resources, finance or health and safety and environment, as they bore no logical linkage to gross margins. The CCA also argued that the use of gross margins, as a profitability measure, allowed DERS to push costs from its unregulated business into a regulated cost of service regime.

The CCA recommended that all corporate costs be allocated according to the number of full-time equivalents employed by Direct Energy North America based on the 2012 average employee count, and therefore recommended that the AUC reduce DERS' corporate cost allocations by 42 percent (or $318,000).

The CCA also took issue with DERS booking AUC approved amounts as "actuals" for the purposes of accounting, on the basis that such accounting practices did not accord with standard industry practice, and was misleading and confusing.

The AUC determined that a 1.0 percent allocation for all corporate costs based on full-time equivalents was not reasonable, finding the CCA's evidence to be persuasive, and therefore reduced the allocation by 42 percent. However, the AUC disagreed with the CCA's recommendation that the reduction be applied to all corporate costs.

The AUC agreed with the CCA's concerns related to DERS' practice of booking AUC approved amounts as actuals, and ordered DERS to cease the practice, and to provide a new corporate costs allocation methodology with its next application.

The AUC also found that DERS' corporate costs were inflated using CPI forecasts, and directed DERS to update its inflation of these costs in accordance with its findings for inflation. The AUC otherwise approved DERS' applied for corporate costs.

Labour Costs

With respect to remuneration for employees, DERS calculated its 2015 and 2016 labour remuneration costs by inflating the 2014 labour forecasts by the CPI, consistent with its inflation forecast of 2.75 percent.

The CCA argued that the remuneration costs should be reduced to the actual costs for 2012 through 2014, and that the forecast amounts for 2015-2016 be based off of the average of the actual data. The CCA also noted that a further full time equivalent vacancy rate be applied to the forecasts, consistent with DERS' actual vacancy rates for earlier years.

The AUC accepted the CCA's recommendation to use the available actual financial data for remuneration, as it was better reflective of DERS' customer base. However, the AUC rejected the CCA's arguments concerning full time equivalent vacancy rates, noting that the application of a vacancy rate to the actual data would result in an under-collection of forecast labour costs, as the actual data already reflects the vacancy rates.

The AUC directed DERS to amend its 2012, 2013 and 2014 labour costs to reflect actual amounts, and to amend its 2015 and 2016 forecasts for remuneration based on the average of 2012-2014 actual costs in its compliance filing.

Working Capital

The AUC approved DERS' working capital forecast and methodology for 2012-2014. The AUC directed DERS to update its 2015 and 2016 forecasts by incorporating the most recent information available in the proceeding, and to update those forecasts to reflect the AUC's findings in Decision 2191-D01-2015 for generic cost of capital matters.

Bad Debt and Un-billable Revenue

DERS requested bad debt costs for:

(a) 2015 of $3.20 million and $1.37 million for its DRT and RRT, respectively; and

(b) 2016 costs of $3.17 million and $1.44 million for its DRT and RRT, respectively.

For un-billable revenues, DERS requested:

(a) 2015 costs of $2.08 million, and $869,800 for its DRT and RRT, respectively; and

(b) 2016 costs of $2.05 million and $914,800 for its DRT and RRT, respectively. DERS used a methodology that applied the average of the previous five years of expenses, escalated by inflation of 2.75 percent for each of bad debt and unbillable revenue.

The UCA submitted evidence that the costs of bad debt had been consistently over-forecasted by DERS by approximately 4.47 percent for the DRT, and 1.21 percent for the RRT on a per-site basis. The UCA also submitted evidence that the un-billable revenue for DERS under its DRT and RRT were over-forecasted by an average of 46.47% and 56.22% respectively.

The AUC rejected DERS' five year average methodology, holding that it did not accurately reflect recent experience. Instead the AUC considered a more reasonable forecasting methodology would be based off of actual costs associated with bad debt and collections for 2012, 2013 and 2014, eliminating the need for any forecast risk adjustments.

Idle sites

DERS submitted that it books un-billable revenue to idle sites in its site count, as these sites still attract distribution and transmission charges. The threshold methodology applied by DERS for a site was a 13 month waiting period before being permanently disconnected. Each site must meet a number of criteria before disconnection, including 12 consecutive months of inactivity, and the removal of the meter.

The AUC accepted DERS' methodology for booking un-billable revenue from idle sites.

Inter-Affiliate Code of Conduct

DERS requested that it not be subject to an Inter-Affiliate Code of Conduct, on the basis that its affiliate with which it has a master services agreement does not operate within Alberta, and its agreement simply provides access to infrastructure (i.e. hardware and software) in a fee for service arrangement at fair market value. DERS noted that it already operates under a compliance plan for its employees in the course of any inter-affiliate transactions.

The AUC rejected this request on the basis that DERS' affiliates took part in unregulated business activities, and the compliance plan DERS operates under was not on the public record, and not approved by the AUC. Therefore the AUC directed DERS to file an inter-affiliate code of conduct for approval by December 31, 2015, consistent with the principles set out in Decisions 2002-069 and 2003-040.

Compliance Filing

The AUC accordingly ordered DERS to submit a compliance filing consistent with the findings and directions above on or before August 21, 2015.

The City of Red Deer 2015-2017 Transmission Facility Owner General Tariff Application (Decision 3599-D01-2015)

General Tariff Application

The City of Red Deer ("Red Deer") applied to the AUC pursuant to sections 37, 119 and 124(2) of the *Electric Utilities Act* for approval of its General Tariff Application ("GTA") for its transmission facilities. Red Deer's GTA consisted of:

(a) Red Deer's proposed revenue requirements for the period from January 2015 to December 2017;

(b) A return on equity deferral account;

(c) A direct-assign deferral account;

(d) A hearing cost reserve; and

(e) A self-insurance reserve.

Red Deer submitted that it had responded to, or complied with all of the AUC's remaining directions from Decision 2013-373, 2013-214, 2013-417 and 2005-149, with the exception of Direction 5 (salvage value of new buildings) from Decision 2013-373. Red Deer advised that it would comply with Direction 5 in filing its next depreciation study.

The AUC found that Red Deer had complied with all outstanding directions, and noted that Direction 5 from Decision 2013-373 would remain outstanding until Red Deer files its next depreciation study.

With respect to cost of debt, Red Deer noted that it did not have a history of debt financing, and used a proxy calculation using the Alberta Capital Finance Authority (ACFA) rate of 2.925 percent (as of July 1, 2014) adjusted to a 15-year rolling average. Red Deer's requested cost of debt rates were as follows:

(a) 2015 – 4.359 percent;

(b) 2016 – 4.137 percent; and

(c) 2017 – 3.924 percent.

The AUC found that the mid-year rate base convention did not apply to interest rates, and therefore ordered Red Deer to apply a 2.235 percent rate to reflect the most recent actual rate recorded for the 2015-2017 period. The AUC ordered Red Deer to use the 2.235 percent rate to calculate its 15-year rolling average rate in its compliance filing.

With respect to inflation assumptions used in developing the proposed revenue requirement for 2015-2016, Red Deer submitted that it used the following assumptions:

Percentage (%) increase	2015	2016	2017
Salary & wages, union	4.0	4.0	4.0
Salary & wages, non-union	3.0	3.0	3.0
Materials	2.5	2.5	2.5
Contractors	4.0	4.0	4.0
General-other	2.5	2.5	2.5

The Consumers' Coalition of Alberta ("CCA") challenged the inflation figures provided by Red Deer, on the basis that the uncertain state of Alberta's economy, and recent downturn in employment figures would not likely remain untouched. Therefore the CCA recommended that the AUC reduce the union wages to reflect the negotiated agreements at 3.5 percent, utilize actual contractor costs as negotiated, and utilize the consumer price index for non-union inflation increases.

The AUC agreed with the CCA and found that Red Deer had not justified the 0.5 percent inflationary increase for union employees, but found that the step increases for long-service employees above 3.5 percent was warranted to some degree. Therefore, the AUC approved an overall inflationary increase of 3.75 percent for union employees, and directed Red Deer to reflect this in its compliance filing.

With respect to contractor wage inflation, the AUC noted that it could not ignore current economic conditions, even if not brought up in evidence. The AUC found that it would be unreasonable for contractor inflation rates to exceed those for Red Deer employees, and therefore applied the negotiated union agreement inflation rate of 3.5 percent as the latest and best arm's-length evidence available for inflation. The AUC directed Red Deer to reflect this change in its compliance filing.

The AUC found that all the remaining inflationary rates requested by Red Deer were reasonable and approved them as filed.

With respect to vacancy rates, the AUC approved a vacancy rate of 1.0 percent for full time equivalents, to reflect the low level of vacancies for Red Deer.

Red Deer requested approval of a depreciation rate of 3.26 percent for its towers and fixtures, consistent with the depreciation rates used by the City of Lethbridge in its 2012-

2014 tariff application. Red Deer submitted that it did not undertake its own depreciation study as it did not previously own transmission lines prior to this application, and its last depreciation study was filed in 2011. Red Deer proposed to true up any variance between its estimated depreciation rate and a rate to be determined during its next depreciation study.

The CCA submitted that depreciation rates used by ENMAX and EPCOR would be more appropriate. However, the AUC determined that the depreciation rates used by Lethbridge were more appropriate and approved Red Deer's depreciation rates as filed, on the basis that the two utilities were comparable in nature, and had similar expected service life of assets.

With respect to Allowance for Funds Used During Construction (AFUDC), Red Deer calculated AFUDC on a gross expenditure basis, and did not recognize the customer contribution obligation prior to completion of two substation projects. Red Deer submitted that it did not include the customer contribution since the contribution is not 'received' as the Transmission Facility Owner and Distribution Facility Owner are part of the same municipal department. Therefore amounts were only added upon the in-service date of the two substation projects.

The AUC disagreed, and held that a customer contribution is to be accounted for as soon as it is confirmed that a contribution will be required for the project. Further, the AUC found that waiting until expenditures are capitalized before contributions are received effectively overstates the rate base due to AFUDC. Despite this, the AUC found that it was reasonable to assume that contributions from the distribution function of Red Deer are recognized simultaneously with costs incurred by the transmission function of Red Deer. Therefore, the AUC directed Red Deer to adjust in its compliance filing, recognition of contributions in its revenue requirement calculations, such that contributions are recognized at the start of construction and accumulated as an offset to project expenditures for calculating AFUDC.

The AUC also approved the continued use of the methodology to allocate costs between transmission and distribution functions for Red Deer, as set out in Decision 2005-149. However, the AUC ordered Red Deer to re-file its corporate allocation costs using 2014 actual allocators for its recent substation projects, as it held that actual figures were a more reliable data source.

Red Deer proposed to include land purchase costs for substation 209S into rate base in 2016, in the amount of \$927,750, comprised of \$914,750 for the cost of the land itself, and \$13,000 paid by AltaLink Management Ltd. ("AltaLink") for land easement and damage claims. Red Deer further proposed to include the AltaLink portion of the substation cost in its rate base, in the amount of \$2.679 million to reflect its contribution.

The CCA questioned why the amounts for the AltaLink portion of the project were being proposed for inclusion in the Red Deer rate base for 2016, arguing that if the ownership of the AltaLink portion resides with AltaLink, that should be reflected in AltaLink's books, not Red Deer's.

The AUC agreed with the CCA, and consequently ordered Red Deer to confirm whether or not the AltaLink portion of the 209S substation costs were included. The AUC directed that if Red Deer cannot confirm that the AltaLink costs were not included, that Red Deer is to remove the \$2.679 million from the substation costs, and the \$13,000 related to land costs, and all associated AFUDC amounts.

The AUC therefore ordered Red Deer to provide a compliance filing within 60 days of this decision, and ordered Red Deer to continue to maintain and reconcile the following deferral accounts in its next application:

(a) Return on equity;

(b) Direct-assign capital;

(c) Hearing cost reserve; and

(d) Self-insurance reserve.

2016 Generic Cost of Capital Application for Finalization of 2016 Approved Return on Equity and Capital Structures (Decision 20371-D01-2015)
Generic Cost of Capital

On May 7, 2015, AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Electric Ltd., ATCO Gas, ATCO Pipelines, ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., and Fortis Alberta Inc. (collectively, the "Alberta Utilities") submitted an application to the AUC to set the return on equity ("ROE") and capital structures for the 2016 year on a final basis. The AUC had previously set the ROE and capital structures for 2013, 2014 and 2015 on a final basis in Decision 2191-D01-2015. In that decision, the AUC also set the ROE and capital structures for 2016 on an interim basis.

The Alberta Utilities applied to accept the interim ROE for 2016 established in 2191-D01-2015, and set the ROE and capital structures for 2016 on a final basis in order to reduce the potential for regulatory lag and to ensure certainty for ratepayers. The Alberta Utilities submitted that certain matters (such as the filing of appeals related to the Utility Asset Disposition hearings) may not accommodate the filing of complete submissions for a potential 2016 generic cost of capital proceeding.

The Office of the Utilities Consumer Advocate, the Consumers' Coalition of Alberta, and the City of Calgary (collectively, the "Customers") partially opposed the proposal, noting the general downward trend in Government of Canada benchmark bond yields. The Customers also submitted that certain equity increases given by the AUC in previous generic cost of capital decisions as a means of providing credit metric relief for specific utilities may no longer be required in 2016. The Customers submitted that many of the Alberta Utilities capital spending programs underpinning such credit metric relief programs may already be complete.

The AUC determined that without support from the Customers, the Alberta Utilities' proposal to set the 2016 ROE and capital structures at levels approved in Decision 2191-D01-2015 would not be in the public interest. The AUC therefore opted to initiate a normal course generic cost of capital proceeding for 2016 and 2017.

The AUC held that regulatory lag with respect to the 2016 ROE can be avoided through strict adherence to the process schedule set by the AUC. While the AUC acknowledged that such an approach may not permit wholly prospective approvals of ROE and capital structures for 2016, it addresses procedural and evidentiary needs, and balances the interests of both the Alberta Utilities and the Customers.

As a result, the AUC determined that the interim 2016 ROE and capital structures will remain in place until changed by a decision of the AUC.

Mr. Yanke and Mr. Huebner Noise Complaints Oldman 2 Wind Farm (Decision 3521-D01-2015)
Noise Complaint – Wind Farm

On November 13, 2014, Mr. Yanke filed a noise complaint with the AUC under AUC Rule 012: *Noise Control* ("*Rule 12*") regarding noise at his residence located near the Oldman 2 Wind Farm (the "Wind Farm"), and approximately 100 metres away from the nearest wind turbine (T-20). Mr. Yanke described the noise emissions as blade whooshing, whipping, pulsating, gear box grinding noise, and high pitch sounds from generators. Mr. Yanke also complained of the red blinking lights from the turbines, and potential for ice to be thrown from the turbine blades during winter.

Mr. Huebner supported the complaint by Mr. Yanke, noting that his residence was equally affected by the Wind Farm.

Mr. Yanke had purchased land and begun constructing his residence in March 2012, completing it in the summer of 2013. Mr. Huebner stated that he purchased his property in December 2012 and completed construction of his house and shop by fall 2013. The Wind Farm was commissioned in late August of 2014.

Oldman 2 Wind Farm Limited, a wholly owned subsidiary of Luxembourg Mainstream Renewable Power S.A.R.L. ("Mainstream") commissioned SLR Consulting (Canada) Ltd. ("SLR") to prepare a sound survey for the Wind Farm in respect of the complaint. SLR conducted a sound survey over a 48-hour monitoring period between March 4 and 6, 2015 concurrently at the Yanke and Huebner residences in accordance with *Rule 12*. SLR stated their opinion that the sound survey captured representative conditions of typical weather conditions with the wind farm operating near capacity during the survey. During the survey, the energy output from the Wind Farm ranged from 49.9 percent capacity to 98.9 percent of capacity, with all turbines operating normally.

After performing isolation analyses on the data available for nighttime sound levels, SLR stated that the valid nighttime data was 79 minutes at the Yanke residence and 87 minutes at the Huebner residence. SLR noted that the low amount of valid data was largely due to wind noise.

Mainstream acknowledged that the valid data was less than the three hours required by *Rule 12*, but relied on SLR's professional opinion that sufficient data was collected to accurately assess sound levels. SLR considered that the sound level contribution of the wind turbines at the Yanke residence was 42.7 dBA Leq nighttime, and 40 dBA Leq nighttime at the Huebner residence. Both of these levels were noted as in excess of the nighttime sound level limits in *Rule 12*.

The AUC accepted that the sound survey was conducted by SLR and calibrated in accordance with *Rule 12*, and that the Wind Farm was operating normally during the sound survey. However, the AUC found that the 48-hour noise study did not capture the minimum requirement of three hours of daytime and three hours of nighttime representative data after isolation analysis in accordance with *Rule 12*. Despite this finding, the AUC determined that the sound survey provided enough information on which to base its findings.

The AUC determined that the isolated nighttime sound levels for the Yanke residence, based on data provided was 42.5 dBA Leq for March 4-5, 2015 and 45.7 dBA Leq for March 5-6, 2015. The AUC determined that the isolated nighttime sound levels for the Huebner residence, based on data provided was 41.8 dBA Leq for March 4-5, 2015 and 43.0 dBA Leq for March 5-6, 2015. The AUC found that these isolated nighttime sound levels for both monitoring periods exceeded the permissible sound level of 40 dBA Leq nighttime in *Rule 12*.

The AUC therefore held that the Wind Farm was not in compliance with *Rule 12*, and ordered Mainstream to:

(a) Immediately restrict operations of the wind turbines contributing to the non-compliance until otherwise ordered by the AUC;

(b) File a letter with the AUC by August 5, 2015 confirming that the operations have been restricted, and detailing the measures taken to achieve compliance with *Rule 12*; and

(c) File a new comprehensive sound level survey at the Yanke and Huebner residences if Mainstream applies to rescind the restricted operating conditions.

Commission-initiated Review Electric Transmission Access Charge Deferral Accounts –Annual Applications (Decision 3334-D01-2015)
AUC Review – Deferral Accounts

EPCOR Distribution & Transmission Inc. ("EDTI"), on behalf of ATCO Electric Ltd. ("AE"), ENMAX Power Corporation ("ENMAX") and FortisAlberta Inc. ("FAI"), (collectively, the "DFOs") filed a joint application for approval of a harmonized schedules template for each company's annual transmission access charge ("TAC") deferral account applications.

The AUC had previously issued Decision 2012-304, which outlined the standardized methodology for the DFOs' quarterly TAC deferral account rider applications. The AUC noted that this led to the development of a uniform approach for filing quarterly TAC deferral account rider applications, and processed by way of filings for acknowledgement, as set out in Bulletin 2015-09. In subsequent 2013 annual TAC deferral account applications, a number of DFOs proposed refinements to the common approach. Accordingly, the AUC initiated the proceeding to determine whether there is an opportunity to harmonize the content and structure of the DFOs' annual TAC deferral account applications and supporting schedules, with a view to developing a common approach in the future.

During consultations, the parties agreed to develop and provide a common name for the annual TAC deferral account application, to include both the true-up year, and the word "annual". The AUC approved the common title "20xx Annual Transmission Access Charge Deferral Account True-up" to be used by parties in future years.

With respect to accounting approaches, the AUC noted that two approaches could be used to determine what amounts collected by way of quarterly Alberta Electric System Operator ("AESO") Demand Transmission Service ("DTS") deferral account riders should be included in a particular year's TAC true-up. One approach would deem all revenue received in a calendar year as part of that year's true-up regardless of what time period the revenue was intended to relate to. The other approach would deem all revenue collected assigned to the period when the revenue should have been earned, otherwise known as an accrual basis.

The AUC held that the accrual basis was the preferred method, noting that all companies except for ENMAX used the accrual basis, and that ENMAX agreed to switch to accrual methods in future TAC deferral account true-ups.

The Office of the Utilities Consumer Advocate (the "UCA") expressed concerns over the different allocation methodologies used by each of the DFOs in their schedules for TAC deferral account applications. While the UCA noted that the allocation methodologies were outside the scope of the proceeding, it submitted that the common flow-through nature of the AESO costs to each of the DFOs strongly supported the adoption of common allocation methodologies.

The AUC determined that while harmonizing content of the applications was a goal of the proceeding, the allocation methodologies themselves were outside the scope of the proceeding, and approved the continued use of each DFO's latest approved cost allocation methodology in its TAC deferral true-up applications.

With respect to carry forward provision amounts, for when the quarterly rider amount impact exceeds 10 percent of a customer's bill, the DFOs proposed to reconcile any amounts in schedule 3 of the proposed forms, as opposed to schedule 8. The DFOs submitted that this would reduce the risk of any possible double accounting of these amounts, since schedule 3 of the proposed forms already calculates the difference between actual revenue collected and TAC charges incurred, net of any carry forward provision amounts. This approach was supported by the UCA.

The AUC accepted this approach, further noting that permitting the option of truing up carry forward provisions in quarterly filings may also have the benefit of avoiding larger true ups from annual applications. The AUC therefore ordered amendments to schedules 3 and 8 to reflect the DFOs' ability to reconcile under schedule 3.

With respect to establishing a common filing date, ATCO and FAI proposed delaying the current deadline of June 30 to ensure more accurate revenue data. EPCOR expressed a preference for as early as possible in a year to facilitate year-end settlements with customers.

The AUC held that there was no need to establish a fixed date, and therefore determined that parties can file annual applications between July 1 and August 10 each year, but that they may opt for an earlier filing date. The AUC also noted that this may assist interested parties in managing workloads by avoiding having to review four concurrent applications.

The AUC also made the following changes to the proposed annual application schedules template:

(a) Changing the application title consistent with the findings above;

(b) Additional footnotes to schedules provided by the DFOs to show the allocation of amounts to customer classes;

(c) Changing schedule 3.3 for the calculation of carry forward amounts; and

(d) Adding columns to schedule 8.0 for Q1 and Q2 of 2015 to reflect the potential for carry forward amounts from 2014 to be cleared in those quarters.

The AUC otherwise approved the schedules template for the TAC deferral account true up applications, and directed the DFOs to use the approved schedules template effective July 21, 2015.

EPCOR Distribution & Transmission Inc. 2015 Interim Transmission Facility Owner Tariff (Decision 20556-D01-2015)
Interim TFO Tariff

EPCOR Distribution & Transmission Ltd. ("EDTI") requested approval of an interim transmission facility owner ("TFO") tariff to be effective January 1, 2015. EDTI requested a continuation of its approved 2015 interim TFO tariff of $6,548,085 per month from January to October 2015, and requested approval to increase the monthly interim TFO tariff to $14,272,786 for November and December 2015.

EDTI submitted that the proposed increase was 50 percent of the difference between the 2015 forecast revenue requirement sought in EDTI's 2015-2017 general tariff application and EDTI's 2014 approved revenue requirement, with adjustments to account for the 2013 generic cost of capital decision. EDTI's 2015-2017 general tariff application proposed a 2015 forecast revenue requirement of $100.84 million.

EDTI also submitted that its proposed interim TFO tariff would mitigate future adjustments, thereby easing any potential rate shock to consumers, and in any event would be made on an interim refundable basis, thereby not prejudicing EDTI's customers.

The AUC noted that no party objected to the application, and that EDTI's interim increase reflected an intermediate position between current rates and proposed final rates, consistent with previous interim rate approvals. However, the AUC found it was not necessary to approve the interim TFO tariff going back to January 2015, as the financial outcome would be identical to the continued application of the current interim TFO tariff. The AUC also noted that the proposed effective date pre-dates the application by seven months, and was therefore not prospective for that period. Accordingly, the AUC found that it was only necessary to approve the interim TFO tariff of $14,272,786 per month in November and December 2015, which would not result in rate shock.

The AUC therefore approved the revised interim monthly TFO tariff of $14,272,786 effective November 1, 2015 to be collected in each of November and December 2015.

Draft amendments to AUC Rule 007 to streamline application requirements for needs identification documents and abbreviated needs identification documents (Bulletin 2015-12)
Bulletin – Rule 007

The AUC announced the release of draft amendments to Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* ("*Rule 007*") to streamline application requirements with respect to needs identification documents as enabled by recent amendments enacted by the *Transmission Amendment Regulation*, AR 175/2014, and the *Transmission Deficiency Regulation*, AR 176/2014. These amendments provided for a number of changes, including clarification and amendment of the requirements with respect to needs identification documents still requiring AUC approval. The proposed requirements, as well as a number of clerical amendments, are reflected in the draft revision of *Rule 007*, a blackline of which can be found here.

The AUC has requested feedback from stakeholders in respect of the draft of *Rule 007* on or before August 14, 2015.

Market Surveillance Administrator Allegations Against TransAlta Corporation et al., Mr. Nathan Kaiser and Mr. Scott Connelly Phase 1 (Decision 3110-D01-2015)
Trading, Compliance and Outage Allegations

In November and December 2010, and February 2011 the Market Surveillance Administrator ("MSA") alleged that, TransAlta Corporation, TransAlta Energy Marketing Corp. and TransAlta Generation Partnership (collectively "TransAlta") intentionally took certain coal-fired generating units, subject to Power Purchase Arrangements ("PPAs"), offline for repairs during periods of high demand, when TransAlta was able to delay those repairs to a period of lower demand, to drive up electricity prices to benefit TransAlta's portfolio (the "Outage Allegations").

The MSA also alleged that TransAlta, Mr. Nathan Kaiser ("Kaiser"), an asset optimizer employed by TransAlta to manage its asset positions in Alberta, and Mr. Scott Connelly ("Connelly") a trader employed by TransAlta to transact in the forward financial energy market, improperly used non-public information regarding the capability of certain TransAlta generating units to produce electricity in 2011 to trade in Alberta's electricity market (the "Trading Allegations").

As part of its allegations, the MSA submitted that TransAlta did not have effective internal compliance policies and practices in place that prevented anti-competitive conduct from occurring regarding the use of non-public outage information, the result of which was a breach of TransAlta's obligations set out in section 6 of the *Electric Utilities Act* ("*EUA*") to conduct itself in a manner that supports the fair, efficient and openly competitive operation of the market (the "Compliance Allegations").

TransAlta denied the Outage Allegations, submitting that timing forced outages at coal plants subject to PPAs to benefit its portfolio was consistent with the governing law and direction it received from the MSA. TransAlta also denied the Compliance Allegations, submitting that it had a robust compliance program for its traders.

TransAlta, Kaiser, and Connelly also denied the Trading Allegations, submitting that they did not have, nor used, non-public outage information. In the case of Kaiser and Connelly, both also submitted that they were not "market participants" as defined in the *EUA*, but rather acting on behalf of TransAlta. Kaiser and Connelly also disputed the procedural fairness of the MSA's investigation of them.

<u>Background Chronology</u>

In February of 2010, the MSA notified market participants that it would host a roundtable discussion and consultation on market participant offer behaviour enforcement guidelines ("OBEG"). In May and June of 2010, TransAlta developed the Alberta Portfolio Bidding Business Case – Executive Summary ("Portfolio Bidding Strategy"), and moved its asset optimizers (including Kaiser) to the trading floor. The Portfolio Bidding Strategy identified two key strategies for capturing higher revenues: economic withholding, and discretionary outages. Subsequently, the Portfolio Bidding Strategy received executive approval on November 18, 2010.

TransAlta timed discretionary outages as follows:

(a) November 19, 2010 at Sundance 5;

(b) November 23, 2010 at Sundance 2,

(c) December 13-16, 2010 at Sundance 2, Keephills 1 and Sundance 6; and

(d) February 16, 2011 at Keephills 2,

(collectively, the "Outage Events").

The MSA released a draft OBEG document on November 26, 2010, seeking input regarding discretionary outages at units subject to PPAs. A final version of the OBEG was released on January 14, 2011, stating that additional considerations may apply to certain fact patterns if a unit is subject to a PPA, and that the MSA offered no guidance on outage timing at PPA units at that time.

On February 26, 2011, the MSA received a complaint regarding the conduct of TransAlta as a PPA owner pertaining to the timing of outages at coal-fired generating units. On March 8, 2011, the MSA issued a Notice of Investigation to TransAlta relating to the timing of outages and instructed TransAlta to retain all relevant records related to the matters being investigated.

As a result of its investigation, the MSA filed an application with the AUC on March 21, 2014 alleging that, in relation to the Outage Events, TransAlta contravened sections 2(h) and 2(j) of the *Fair, Efficient and Open Competition Regulation* (the "*FEOC Reg*") and section 6 of the *EUA*.

Sections 2(h) and 2(j) of the *FEOC Reg* state that conduct by a market participant that manipulates prices away from a competitive outcome or otherwise restricts or prevents competition or a competitive response does not support the fair, efficient and openly competitive operation of the market. The MSA also alleged that the conduct of TransAlta, Kaiser and Connelly with respect to trading activities around the Outage Events contravened section 4 of the *FEOC Reg* and section 6 of the *EUA*.

<u>Consideration of Evidence</u>

The AUC determined that the standard and burden of proof in this proceeding would be on a balance of probabilities. The AUC also determined that the MSA would have the burden of demonstrating the occurrence of the alleged contraventions.

However, the AUC noted that where the defence of due diligence was applied, the respondents TransAlta, Kaiser and Connelly would bear the onus of proving that they took all reasonable care on a balance of probabilities.

With respect to circumstantial evidence, the AUC ruled that it was capable of drawing inferences from circumstantial evidence relied upon by the MSA, but noted the limitations requiring that any such evidence be clear, convincing and cogent.

On matters of expert evidence, the AUC noted that expert evidence would be admissible if it was relevant, necessary to assist the trier of fact, not excluded by any rule, and if the expert had the necessary qualifications.

TransAlta submitted that the expert testimony of Dr. Matt Ayres ("Ayres") should be given little to no weight due to a lack of impartiality. Ayres authored an expert report for the MSA on price impacts associated with the Outage Events. TransAlta submitted that Ayres was the lead investigator for the MSA, played a leading role for the MSA during consultations on the OBEG matters, and drafted the MSA's notices, therefore impugning his independence and impartiality.

TransAlta made similar submissions with respect to the expert evidence of Dr. Jeffrey Church ("Church"). Church authored a report for the MSA that addressed competition matters including market power. TransAlta submitted that Church's evidence lacked independence on the basis that Church had an economic relationship with the complainant that launched the initial investigation, and that Church's responses were evasive in testimony and were reflective of a conflict of interest. TransAlta also questioned Church's independence based on his prior working relationship with one of the MSA's investigators who was a former graduate student under Church and had co-authored a paper together. TransAlta also submitted that the expert report of Church should be given little to no weight.

The MSA argued that admissibility of expert evidence was not an issue, as no party objected to the qualification of the witnesses during the pre-qualification process set out by the AUC. The MSA stated that Ayres was independent of any market participant and served the MSA's legislated mandate in good faith. The MSA submitted that, as an expert body, it should not be prevented from utilizing its own expertise in performing its statutory mandate. The MSA also submitted that Church had no discussions with the MSA investigator in question and was not working for any party in the proceeding. The MSA also noted that Church's curriculum vitae showed that he had worked for a number of market participants previously, including TransAlta.

The AUC held that it was satisfied that each of the experts in the proceeding was able to carry out his or her respective duty to provide the AUC with fair, objective and non-partisan evidence, and did so under oath or affirmation. As a result, the AUC held that all of the expert evidence filed was admissible as such.

Specifically, with respect to Church's evidence, the AUC determined that Church's reluctance to answer questions about his previous employment was not evasive, and that his reluctance to identify the unnamed complainant arose from a contractual and professional duty of confidentiality, and that Church went to considerable lengths to respect those obligations. The AUC also found no reason to discount the expert evidence on the basis of prior academic work with an MSA investigator, as the AUC had no evidence before it that suggested it affected the expert evidence provided.

With respect to Ayres' evidence, the AUC found that a mere employment relationship was generally insufficient to render evidence inadmissible, but noted that the "party" and "expert" in this instance were nearly one and the same, which would normally lead to considerable concern over the evidence in question. However, the AUC found that the following factors mitigated those concerns:

(a) The nature of the expert evidence as counterfactual evidence in analyzing alternative outage timings. The AUC noted that Ayres relied on other expert reports for his inputs, and his calculations were transparent;

(b) TransAlta's own experts had an opportunity to critique Ayres' work, and provided commentary on what they believed were shortcomings in Ayres' work;

(c) The AUC's own expertise and familiarity with economic analysis and the Alberta electricity market;

(d) Ayres was experienced and knowledgeable with respect to the Alberta electricity market and was well qualified to perform his analysis; and

(e) The MSA's duty to carry out its responsibilities in a fair and responsible manner. As chief economist at the MSA, the AUC found that Ayres appreciated this duty and performed his job obligations in good faith.

<u>Outage Allegations</u>

The MSA submitted that sections 2(h) and 2(j) of the *FEOC Reg* were strict liability offences, requiring only that the MSA prove the events occurred and harmed the market, subject to the defence of due diligence from TransAlta.

The MSA argued that the Outage Events were discretionary outages, as the boiler tube leaks and other mechanical problems noted by TransAlta were not significant, and operations could have continued in a steady state. The MSA referenced statements by TransAlta to the effect that the nature of the leaks in question did not require an immediate outage, although the unit would have to come offline in the near future.

The MSA argued that the timing of the outages was not determined by good operating practices by operation staff, but rather dictated by the marketing and trading group. The MSA testified that TransAlta had scheduled the outages at times of high demand and tight supply with the aim of driving up the pool price for the benefit of TransAlta's Portfolio Bidding Strategy, and to the detriment of buyers under the PPAs, thereby constituting a breach of section 2 of the *FEOC Reg* and section 6 of the *EUA*.

The MSA provided expert evidence and data showing that discretionary outages were usually taken during off-peak hours by owners of the PPAs, so that the reliability to the Alberta Interconnected Electrical System ("AIES") was not compromised, and mitigated upward pressure on pool prices. The MSA also provided evidence that boiler leaks and mechanical problems were common, and well understood by market participants such as TransAlta, and were typically scheduled over weekends or at night. The MSA therefore argued that, after reviewing the logs from TransAlta in respect of the Outage Events, the units could have been taken off during off-peak hours.

TransAlta developed its Portfolio Bidding Strategy in the fall of 2010. It identified two key strategies for capturing higher revenues: economic withholding and discretionary outages, stating that "the aim of both strategies is to move settled pool price higher by physically removing MW from the supply curve by offering them in at a higher price or by removing [them] from the system altogether." TransAlta implemented the Portfolio Bidding Strategy on November 19, 2010.

TransAlta made two main arguments in respect of the Outage Events. First, that the buyers of the PPAs received the electricity that they were entitled to under the arrangements. Second, TransAlta had the unfettered right to time its outages pursuant to section 5.2 of the PPAs to "interrupt the provision of Generation Services from any Unit at any time to the extent necessary to safeguard life, property or the environment, or to the extent reasonably necessary to conduct preventative maintenance" to safeguard the same. TransAlta submitted that during the Outage Events, TransAlta staff noted boiler tube leaks and other mechanical problems, thereby necessitating a forced outage for safety reasons. TransAlta noted that the operations staff provided a range of timing for outages for the plants in question, after discovering the leaks, and that the asset optimizers provided recommendations for the specific start times within the range suggested by operations staff. Therefore, TransAlta argued, it had acted in accordance with its obligations under the PPAs.

The AUC determined that the PPAs are a component of a comprehensive statutory scheme enacted to ensure the fair efficient and openly competitive operation of the electricity market in Alberta, as the PPAs were incorporated by virtue of the *Power Purchase Arrangement Determination Regulation*.

The AUC noted that the competitive generation market was first imposed on the preceding regulatory structure through the creation of PPAs that were designed to reduce the market power of the three incumbent generators, thereby stimulating greater competition. In finding that the intent of the *EUA* was to establish an efficient market based on fair and open competition, the AUC determined that section 6 of the *EUA* established a positive duty on market participants to conduct themselves in a manner that supports the fair, efficient and openly competitive operations of the electricity market, including under PPAs.

The AUC also determined that section 2 of the *FEOC Reg* sets out conduct that breaches the positive obligation established by section 6 of the *EUA*. However, the AUC noted that the text of section 2(h) of the *FEOC Reg* did not contain any qualifying language, such as "unduly", or "substantially", and therefore the interpretation of events that restrict or prevent a competitive response need not be expressly limited to those found in section 2(h) of the *FEOC Reg*. The AUC also determined that the absence of qualifying language in section 2(h) of the *FEOC Reg* signalled an intention that it would apply to all conduct that prevents competition or a competitive response.

Based on the plain and ordinary meaning of the provisions, the AUC concluded that the conduct prohibited must be conduct undertaken with an anticompetitive purpose, demonstrated on a balance of probabilities. However, the AUC found that it did not require direct evidence of subjective intent, but that the intent could also be proven indirectly on the basis that a person intends the reasonably foreseeable consequences of its acts. The AUC did agree with TransAlta with respect to section 2(j) of the *FEOC Reg*, holding that the use of the word "manipulating" in the section implied that proving an anticompetitive purpose was an element of the offence.

Based on this assessment, and the lack of qualifying language, the AUC considered that the prohibited conduct in section 2 of the *FEOC Reg* was a "*per se*" offence, in that the conduct enumerated is anticompetitive in and of itself without the need to assess the economic impact of the conduct. Therefore, the MSA did not have to demonstrate that the conduct resulted in competitive harm, but rather demonstrate the movement of market prices away from a competitive market outcome.

The AUC determined that the offences were strict liability offences, meaning that there is no necessity for the prosecution to prove the *mens rea* (or intent, knowledge or recklessness). Strict liability offences also leave open to the accused the defence of due diligence, by proving that they took all reasonable care to either avoid the event, or that the accused reasonably believed in a mistaken set of facts. The AUC noted that if it were to require proof of wrongful intention, it could introduce significant barriers to effective regulatory oversight and prevention of conduct that does not support the fair, efficient and openly competitive operation of the electricity market. Therefore the AUC determined that the burden of proof did not require the MSA to demonstrate any element of subjective intent on behalf of TransAlta, and that the defence of due diligence was available to TransAlta.

The AUC determined that the Outage Events were discretionary in nature, finding that none of the Outage Events required an immediate outage. All of the outages were deferred beyond ten minutes, thereby meeting the MSA's definitions of discretionary outages. The AUC also placed significant weight on the fact that the units continued to run at a steady state (and in some cases, for several days) from the detection of the problems until shut down at the times selected or requested by the asset optimizers from TransAlta's marketing and trading departments. The Outage Events, in the AUC's determination, were therefore primarily scheduled for the purposes of TransAlta's Portfolio Bidding Strategy, and not to safeguard life, property or the environment.

While the AUC acknowledged TransAlta's evidence that plant operators had the final say on outages, the AUC noted the overwhelming evidence to show that the operators deferred to the asset optimizers on questions of outage timing. Therefore, on a balance of probabilities, the AUC determined that the MSA demonstrated that TransAlta's determination on the timing of the Outage Events was to advance its Portfolio Bidding Strategy, and not safety.

The AUC held that while the results of the two competing expert reports differed due to the assumptions used, each report clearly demonstrated an increase in average pool prices due to the specific outage timings chosen by TransAlta.

The AUC found that the reasons TransAlta engaged its Portfolio Bidding Strategy was to increase uncertainty and thereby influence forward markets, and was supported by TransAlta's own documents. Therefore, the AUC determined that the Outage Events impacted pool prices, however, due to the limited evidence submitted on the issue, the AUC made no finding in respect of the magnitude of any such effects.

On questions of market power, the AUC held that the nature of the PPAs themselves gave rise to an imbalance of power as between the owner and buyer, as the owner has potentially valuable information about the need, nature and extent of the outage which no other market participant holds. On this basis, the AUC dismissed TransAlta's arguments that the buyers and owner under the PPAs were not competitors.

Therefore, the AUC found that by timing outages subject to PPAs based on market conditions rather than for safeguarding life, property or the environment, TransAlta unfairly exercised its discretion under the PPAs for its own advantage, and for an anticompetitive purpose by restricting or preventing them from providing a competitive response. The AUC held that the conduct in question was contrary to the purpose, spirit and intent of the *EUA* and undermined the fair, efficient and openly competitive operation of the electricity market.

The AUC acknowledged that the market may be influenced by other market conditions, but held that the removal of capacity under the PPAs from market supply nonetheless had the potential to move the pool price away from its competitive level, all else being equal. The AUC further determined that only TransAlta knows whether it is going to implement its Portfolio Bidding Strategy when it trades on the forward market, whereas other parties only have a probabilistic view. Therefore the AUC reasoned that TransAlta was also capable of exploiting forward markets in an ongoing manner.

On the question of economic harm, the AUC determined that it was not required to find that the impugned conduct caused economic harm under section 2(h) of the *FEOC Reg*, since it was a *per se* offence. Nevertheless, the AUC did find that TransAlta's conduct resulted in economic harm. Relying on its earlier determination that TransAlta could have deferred the Outage Events, the AUC found that TransAlta's conduct was deliberate and designed to move market prices away from a competitive outcome during times of high demand and/or constrained supply.

With respect to TransAlta's defences of due diligence, officially induced error and abuse of process, the AUC applied the principles enumerated in Bulletin 2010-17, which provides that the respondent must have put procedures in place that address reasonably foreseeable breaches of laws, regulations and rules.

The AUC held that the evidence did not support the claim that the MSA provided clear, unequivocal and binding advice condoning the Portfolio Bidding Strategy, and TransAlta should have exercised considerable care in making efforts to avoid breaching the *EUA* and *FEOC Reg*. Rather, the AUC determined that the hypothetical scenarios discussed were ambiguous. The AUC noted that TransAlta did not follow up with the MSA, nor seek to clearly confirm its interpretation on these scenarios. If TransAlta wished to solicit advice from the MSA in respect of its Portfolio Bidding Strategy, TransAlta should have done so fully and frankly, and in sufficient detail to permit the MSA to provide the appropriate advice.

For officially induced error, the AUC held that in order for TransAlta to meet its burden, it would have to prove the existence of:

(a) An error of law or mixed fact of law;

(b) TransAlta's consideration of the legal consequences of its actions;

(c) The advice TransAlta obtained having come from an appropriate official;

(d) The advice having been reasonable, but erroneous; and

(e) TransAlta's reliance on the evidence in committing the act.

The AUC dismissed the defences, relying on the context in which the MSA provided its advice, noting that the MSA advised TransAlta that consultation discussions were not considered binding statements of MSA policy. Therefore, the AUC considered it unreasonable for TransAlta to rely on the information provided by the MSA.

As a result of the above finding, the AUC concluded that for the Outage Events, TransAlta restricted or prevented the buyers of the PPAs from providing a competitive response contrary to section 2(h) of the *FEOC Reg*, and further manipulated market prices away from a competitive market outcome.

Trading Allegations

The trading allegations were focused on three emails between Kaiser, Connelly and TransAlta that the MSA alleged used non-public records to trade. The first email, dated December 3, 2010 from a TransAlta employee to Kaiser and another TransAlta employee sought analysis of outages of various durations on the Sundance 2 unit. The second email, dated January 6, 2011 from Kaiser to Connelly and others, contained extracts of a Calgary Herald article on outages at Sundance 1 and 2. The third email, dated January 6, 2011 from Kaiser to Connelly and another TransAlta employee requested the purchase of "100 MW of Feb at market to cover the January balance of month and February."

With respect to the status of each respondent as a market participant, Kaiser and Connelly both submitted that they were not market participants as defined in the *EUA* on the basis that the enactments included employees as operating under a market participant, however TransAlta conceded that it was a market participant. The MSA submitted that based on the plain and ordinary wording of the *EUA*, Kaiser and Connelly were market participants as they exchanged, traded, purchased or sold electricity, electric energy, electricity services or ancillary services.

The AUC determined that the context of each provision provided ample interpretive assistance, and that Kaiser and Connelly were market participants, noting that the provisions were drafted in the widest terms possible due to their frequent use in the legislation, and did not typically differentiate between a business entity and its employees. Therefore, the AUC held that "market participant" in the context of section 6 of the *EUA* applied to individuals as "market participants".

The MSA alleged that the first two emails were non-public outage records, and Kaiser used these records to trade, directly or indirectly on January 6 and 7, 2011. Connelly was alleged to have used the outage records to trade directly or indirectly between January 6 and 21, 2011. The MSA alleged that these acts constituted a breach of section 4(1) of the *FEOC Reg*, which prohibits market participants from using non-public outage records to trade, subject to exemptions from the Alberta Electric System Operator ("AESO").

The MSA submitted that TransAlta had recently become aware of corrosion fatigue problems at Sundance 1 and 2, and sought to plan for several outage scenarios of between 55 and 343 days in length to make repairs. In the course of providing the outage scenario information, Kaiser advised that he would be prevented from taking any action on his remaining 2011 trading positions, but sought clarification from other TransAlta employees. Kaiser was later advised by management that the records were not non-public outage records, and was eligible to continue trading. TransAlta later decided to take down Sundance 1-4 due to boiler leakage issues in December 2010, and trading for all personnel was suspended on December 17, 2010, and reinstated on December 29, 2010 after the information was provided to the PPA buyer and the AESO that Sundance units would be offline until mid-February 2011.

Kaiser sought additional confirmation from TransAlta management that he could instruct trades after December 29, 2010 and received confirmation that he did not have any non-public information.

TransAlta declared a force majeure on the Sundance units for boiler tube repairs, with an estimated in-service date of February 15, 2011. Kaiser later emailed an extract of a Calgary Herald article to the traders on January 6, 2011 highlighting that "TransAlta has no clear picture of when the units will be back in service [...] A decade ago TransAlta's now-retired Wabamum 4 unit was shut down for nine months due to similar issues with corrosion."

Kaiser emailed Connelly later that day at 10:49 a.m. seeking to buy 100MW of February capacity at market to cover the balance of the month in January and February due to the risk of outages at Sundance being extended.

Records showed that Connelly purchased a total of 155 MW of February flat contract on January 6, 2011: 50 MW prior to receiving any of the above emails; 100 MW after receiving the Calgary Herald article, and 5 MW after receiving both emails.

The AUC interpreted section 4 of the *FEOC Reg* as having three main objectives:

(a) Establishing a prohibition on trading non-public outage information;

(b) Establishing an obligation for market participants to file outage records with the AESO; and

(c) A process for the AESO to make outage records public, or to grant exemptions on the prohibition on trading.

Therefore, if a record is not public and not exempt, it cannot be used to trade. The AUC, based on the plain and ordinary meaning, found that "outage record" referred to any information that relates to the ability of a generating unit to produce electric energy, including whether or not it can produce energy at a particular time. However, the AUC noted a materiality threshold for such records.

The AUC determined based on the factual background, that Kaiser had knowledge that the problems with boiler corrosion on the Sundance units could last between six and twelve months, and could therefore reasonably be expected to have a material impact on market prices, given the magnitude of capacity that could be removed from the Alberta electricity market. Therefore, the AUC concluded that Kaiser had possession of an outage record, but the MSA failed to prove that the second email in question was a non-public outage record.

The AUC found that Kaiser's trade instruction noting "there is some risk to the outages at Sun 1/2 being extended" was non-public information, given Kaiser's knowledge of the extended outage scenarios lasting up to 343 days which was never shared with the public. The AUC further determined that Kaiser used the information he had with respect to the capability of the Sundance units to produce electricity to trade when he instructed the purchase of 100 MW at market price on January 6, 2011 and 50 MW on January 7, 2011. The AUC however found that Kaiser had met the defence of due diligence by expressing his immediate concern in respect of the non-public outage information, and by removing himself from trade positions, thereafter seeking advice from TransAlta management on whether the document was an outage record on two separate occasions. Therefore, Kaiser had not breached section 6 of the *EUA*.

The AUC found, that the MSA failed to meet its evidentiary burden against Connelly, as the information in the two emails from Kaiser to Connelly did not contain non-public information about the capability of generating units to produce electricity, and none of the emails from Kaiser to Connelly relayed the non-public outage information possessed by Kaiser. The AUC further found that Connelly's trading activity was consistent with historical trading patterns and the price forecast Connelly had been provided with at the time.

With respect to the allegations against TransAlta, the AUC held that management knew or reasonably should have known that Kaiser had non-public information regarding the Sundance units, which could reasonably be expected to have a material impact on market prices, as Kaiser sought guidance on his trading restrictions. The AUC found that TransAlta should have maintained its trading blackout of Kaiser on the basis of his information. Therefore, by allowing Kaiser to trade while in possession of non-public outage information, TransAlta also breached section 4(1) of the *FEOC Reg* by providing or allowing status information in respect of the Sundance generating units to be provided to a trader outside of a non-trading period, in violation of TransAlta policies. The AUC also noted that TransAlta did not seek advice from its regulatory group or legal counsel with respect to Kaiser's trading activities, which the AUC found was evidence that TransAlta did not take all reasonable steps available to it.

Compliance Allegations

The MSA submitted that TransAlta did not have effective internal compliance policies and practices to prevent anticompetitive conduct from occurring, especially in respect of non-public outage information. The MSA reasoned that this substandard practice was a breach of the positive obligation in section 6 of the *EUA* to support a fair, efficient and openly competitive operation of the market. Specifically, the MSA argued that the following were evidence of compliance policies which did not effectively prevent trading contraventions:

(a) The co-location of asset optimizers with traders;

(b) Allowing the self-regulation of asset optimizers for non-public information;

(c) Allowing asset optimizers to notify traders of non-public outage information about to go public in anticipation of trading on the information;

(d) Taking no action with respect to reported non-compliances from asset optimizers;

(e) Failing to apply oversight practices with respect to the Portfolio Bidding Strategy with respect to information sharing; and

(f) Failing to retain relevant documents and records and failure to prevent their loss or deletion.

The AUC dismissed the Compliance Allegations, noting that the MSA did not give any detailed evidence about compliance plans and conduct in the industry, nor how TransAlta's practices measured up to any such industry standard. The AUC also placed significant weight on the MSA not calling any expert evidence in respect of benchmarks for compliance plans. Accordingly, the AUC found that it could not conclude that TransAlta's compliance plans were inadequate on the evidence before it.

Decision

In the result, the AUC determined the following with respect to the Outage Allegations:

(a) TransAlta timed outages at its coal-fired generating units subject to PPAs on the basis of market conditions rather than by the need to safeguard life, property or the environment as described in Article 5.2 of the PPAs on four occasions:

   (i) November 19, 2010 at Sundance 5;

   (ii) November 23, 2010 at Sundance 2;

   (iii) December 13-16, 2010 at Sundance 2, Keephills 1 and Sundance 6; and

   (iv) February 16, 2011 at Keephills 2;

(b) TransAlta was capable of deferring the events above to off-peak hours, but elected to take them during peak or super-peak hours for the benefit of its own portfolio;

(c) TransAlta's timing of outages increased pool prices above what they otherwise would have been had the outages been scheduled for off-peak hours;

(d) The implementation of the Portfolio Bidding Strategy affected forward markets, however the AUC made no finding on the magnitude of the effects associated with the outages;

(e) Each of the four outage events prevented a competitive response from the respective buyers under the PPAs, contrary to section 2(h) of the *FEOC Reg* and section 6 of the *EUA*;

(f) TransAlta failed to establish the defence of due diligence or officially induced error for any of the four outage events; and

(g) TransAlta failed to demonstrate that the MSA's investigation into the outage events was an abuse of process.

In the result, the AUC determined the following with respect to the Trading Allegations:

(a) TransAlta, Kaiser and Connelly were "market participants";

(b) On January 6 and 7, 2011, Kaiser used non-public outage records to trade contrary to section 4(1) of the *FEOC Reg*;

(c) Kaiser took all reasonable steps to avoid a breach by seeking and getting direction from senior management at TransAlta on his continued eligibility to trade on two separate occasions after receiving non-public outage records. Kaiser therefore established the defence of due diligence and therefore the AUC could not conclude that Kaiser breached section 6 of the *EUA*;

(d) The MSA failed to demonstrate that Connelly had or used non-public outage records to trade during the period between January 6 and 21, 2011 or that Connelly otherwise breached Section 6 of the *EUA*;

(e) TransAlta breached section 4(1) of the *FEOC Reg* and section 6 of the *EUA* by allowing Kaiser to trade while in possession of a non-public outage record;

(f) TransAlta has not established the defence of due diligence with respect to the trading allegations; and

(g) The MSA carried out its mandate in a fair and reasonable manner throughout its investigation and during the hearing.

With respect to the Compliance Allegations, the AUC determined that the MSA failed to demonstrate on a balance of probabilities that TransAlta breached section 6 of the *EUA* on the basis that its compliance policies, practices and oversight thereof, were inadequate and deficient.

Initiating a generic proceeding to address the income tax methodologies used in revenue requirement calculations for regulated utilities in Alberta (Bulletin 2015-13)
Bulletin – Generic Proceeding – Income Tax Methodologies

The AUC announced the initiation of Proceeding 20687 (the "Proceeding") to address the methodologies and treatment of income tax for all utilities regulated by the AUC. All utilities subject to income tax legislation are pre-registered in the Proceeding, whereas municipally owned utilities will not be pre-registered, but may do so later.

Parties may file statements of intent to participate on or before August 12, 2015.

The AUC requested that parties involved in the Proceeding provide written submissions on their views regarding each of the issues. Written submissions from parties are due on September 2, 2015.

The Proceeding would consider four main issues with respect to income tax:

(a) Income tax methods or treatments;

(b) Income tax deferral accounts;

(c) Performance - Based Regulation ("PBR") implications; and

(d) Other considerations.

Under the first issue of tax methods and treatments, the AUC noted that it will consider, among other items:

(a) New methods and treatments for income tax identified by parties;

(b) The extent to which utilities are able to control income taxes and whether incentives should be built into regulatory processes;

(c) Factors relevant to assessing the suitability of a method in specific circumstances;

(d) The nature of the future component of income taxes as a cost or expense recoverable under a tariff consistent with AUC regulatory legislation; and

(e) Whether utilities should be assumed to claim the maximum allowable deductions for income tax purposes for inclusion in revenue requirement.

With respect to PBR implications, the AUC noted that it would consider:

(a) Whether a "Y factor" treatment for distribution facilities under PBR would be necessary for methods identified under the first issue;

(b) Whether and how any benefits or consequences of income tax assumptions and practices should be accounted for between shareholders and ratepayers; and

(c) Any implications that may result from a change in income tax method or treatment.

A full list of the issues can be found here.

NATIONAL ENERGY BOARD

Alliance Pipeline Ltd. as General Partner of Alliance Pipeline Limited Partnership Application for Approval of New Services and Related Tolls and Tariffs (Reasons for Decision RH-002-2014)
New Services Offering – Tolls and Tariffs

On July 9, 2015, the NEB released its decision regarding an application filed by Alliance Pipeline Ltd. as General Partner of Alliance Pipeline Limited Partnership ("Alliance") for approval of new services offering and related tolls and tariffs (the "*Decision*"). Alliance described its new services offering as an "at-risk" business model, deviating from the traditional cost of service model by assuming the risks of providing a variety of service offering and tolling options to generate revenues.

In its application, Alliance requested the orders and approvals necessary to implement new services and related tolls and tariff on the Alliance Pipeline (the "Alliance Pipeline") commencing December 1, 2015 (the "Application"). Specifically, Alliance requested the following:

(a) An order pursuant to Part IV and section 60(1)(b) of the *National Energy Board Act* (the "*NEB Act*") approving the tolls and tariff for the New Services Offering (the "NSO");

(b) Approval of the mechanisms for, and calculation of, the Recoverable Cost Variances ("RCV") demand and commodity surcharges and the Alliance Pipeline abandonment demand and commodity surcharges, including the approval and operation of the requested deferral accounts for the RCV and for collection of Alliance's NEB-approved annual collection of pipeline abandonment funds;

(c) Approval of a streamlined regulatory process for new services and new or revised tolling proposals;

(d) An order or orders for the conversion of the existing agreements for transportation service to continue under the NSO;

(e) Continued relief from the requirement to file with the NEB quarterly surveillance reports ("QSRs") and performance measures; and

(f) Such further and other relief as Alliance may request or as the NEB may deem appropriate, pursuant to section 20 of the *NEB Act*.

<u>Notional Revenue Requirement</u>

As a key part of its NSO, Alliance requested the development of a notional revenue requirement ("NRR"), a cost-based, long-term revenue requirement for 2016-2025 using a levelized value over the 10 year period. Alliance stated that the changes from its existing tariff transferred many business and revenue risks to itself, and was therefore developed as a starting point for the derivation of fixed tolls throughout the 2016-2025 period.

The NEB opted to not rely on the NRR or associated cost information, finding that the financial outlook for the Alliance Pipeline was not a sound basis for derivation of tolls, and noted that the Application would have been rejected under a cost-of-service model as being inadequate. Instead, the NEB relied on the market acceptance of the NSO, and the appropriateness of the Precedent Agreement Process in deriving just and reasonable tolls. The NEB found that:

(a) Alliance's risk had been reduced considerably since the filing of the Application; and

(b) There had been significant uptake of the NSO since the Application was initially filed, resulting in additional certainty of firm contract levels for the next six years.

<u>NSO</u>

The NEB approved the NSO on the basis that each of the new services proposed was reasonable and would provide shippers with the flexibility to use services tailored to their needs. However, the NEB introduced specific limitations in order to better balance the risks faced by Alliance. Alliance was granted the ability to establish bid floors by receipt point or region, but was not granted unlimited pricing discretion. The NEB set the following limitations on Alliance's pricing discretion:

(a) The bid floor for seasonal services may be set between 100 per cent and 125 per cent of the corresponding fixed five-year toll;

(b) The bid floor for interruptible services may be set at any level up to 125 per cent of the corresponding fixed five-year toll;

(c) Discounting is permitted for interruptible services due to its limited availability however, discounting of seasonal services below the firm service toll so as not to undermine the value of firm service will not be allowed; and

(d) Firm shippers using Priority Interruptible Transportation Service ("PITS") will pay a maximum of 125 per cent of the corresponding five-year toll.

The NEB held that it provided both Alliance and its shippers with the tools required to adapt to an evolving business environment, and found the proposed NSO to be just and reasonable. The NEB indicated that it expects these tools to be used to achieve positive outcomes for market participants.

RCV

With respect to the RCV, Alliance submitted that it would only apply the RCV to the following cost categories, on the basis that they were outside of Alliance's reasonable control:

(a) Pipeline integrity, pipe replacements and re-routes;

(b) Property and business tax;

(c) NEB cost recovery;

(d) Compressor fuel tax; and

(e) Environmental levies, such as carbon taxes and greenhouse gas compliance costs.

Alliance further submitted that the RCV was appropriate, as Alliance had assumed cost and revenue risk with respect to other portions of the NSO through the at-risk tolling model. None of the interveners made comments on the RCV. Accordingly, the NEB found that these costs were reasonably outside the control of Alliance, and held that deferral accounts for the RCV were appropriate.

Conversion of Existing Agreements to NSO

Some interveners argued that they should remain entitled to Authorized Overrun Service ("AOS") on the basis that their previous transportation contracts, which had been renewed past the proposed in-service date of the NSO, afforded this service offering.

Alliance stated that it offered conversion options to each of the existing shippers with contracts extending past the proposed in-service date of the NSO, and that the conversion services would result in a lower toll than previously existed for the equivalent capacity. Alliance also argued that the NEB has the authority to affect contracts between Alliance and existing shippers by finding that the tolls were just and reasonable, and was expressly able to do so under the terms of the existing transportation contracts, which allowed for changes to Alliance's tariff.

The NEB agreed with Alliance on this issue, finding that renewal shippers do not have a perpetual right to continue to receive service under their existing contracts, since the contracts themselves explicitly contemplate changes to the tariff. Therefore the NEB granted Alliance's request for a conversion of existing agreements to the NSO.

Streamlined Regulatory Process and QSRs

Alliance requested an 8-week regulatory process, similar to the 10-week timeline approved in the TransCanada Mainline, as adopted in the RH-003-2011 Reasons for Decision. Alliance also requested continued relief from filing QSRs as it was not aware of any reason for discontinuing the exemption.

The NEB took the view that a streamlined process was not necessary at this time, choosing instead to determine the process to follow at the time of any future application related to the NSO. With respect to the QSR, the NEB denied the requested relief, holding that the appropriateness of the exemption no longer exists, and that the NEB requires transparent information due to the unique nature of the NSO. The NEB therefore ordered Alliance to file the following information annually:

(a) Rate of return on common equity and total capital;

(b) Audited financial statements; and

(c) Five years of time series data on integrity spending.

The NEB also ordered Alliance to file the following information on a quarterly basis:

(a) Income statements including revenues and expenses by service type;

(b) Expenses related to RCV cost categories;

(c) Rate base information divided into major categories;

(d) Daily throughput data in GJ, cubic meters and Bcf and key points;

(e) Capacity of the system at each key point, and explanations for any deviations from nameplate capacity;

(f) Deferral account balances;

(g) Details for transactions over $100,000;

(h) Bid information determined in consultation with shippers; and

(i) AECO-C and Chicago city gate price information.

Decision

In the result, the NEB held that:

(a) The new services and associated terms and conditions, are approved as filed;

(b) The proposed toll methodology will produce firm tolls that are just and reasonable, and not unjustly discriminatory and accordingly, the firm tolls are approved as filed;

(c) The approved tolls and tariff will apply to all transportation services provided by Alliance on or after December 1, 2015;

(d) Alliance's proposal for recovering costs that are outside of its control and difficult to forecast through an RCV surcharge and deferral accounts is appropriate. Alliance is required to provide details of the cost categories eligible for inclusion in the RCV to enhance transparency for shippers and the NEB;

(e) Alliance's abandonment surcharge methodology and deferral accounts are approved. Alliance is expected to provide the NEB information or studies to support a collection period of 40 years on the next NEB review of set-aside and collection mechanisms;

(f) Alliance is required to implement a reserve account to hold cash earnings above a threshold level, to be established by a compliance filing. Prior to making any distributions from the reserve account, Alliance must file a depreciation study, for NEB approval;

(g) Alliance's request to implement a streamlined regulatory process is denied; and

(h) Alliance's request for continued relief from the requirement to file QSRs is denied.

Orca LNG Ltd. Application, dated 4 September 2014, for a Licence to Export Gas as Liquefied Natural Gas (July 27, 2015 Letter Decision)
Export Licence - LNG

Orca LNG Ltd. ("Orca LNG") applied for a licence to export gas as liquefied natural gas ("LNG") pursuant to section 117 of the *National Energy Board Act*. Orca LNG requested the licence for a period of 25 years, starting on the first date of export, at a point located at the loading arm of a proposed natural gas liquefaction terminal near Prince Rupert, British Columbia.

Orca LNG applied for an export volume of 1,344 Bcf, or 38.06 billion cubic metres annually. The maximum quantity of the licence would be for 31,800 Bcf, or 901 billion cubic metres.

Orca LNG submitted that the quantity of LNG proposed for export would not exceed the surplus remaining after allowance for foreseeable consumption in Canada. Orca LNG provided two reports forecasting Canadian consumption, long term gas supply and demand forecasts, and an outlook of Canadian LNG exports. Orca LNG's reports noted that Canada's gas markets were open and liquid, as well as supplied by a robust resource base. Orca LNG included nearly all of the NEB approved exports in its forecasts, up to 21.2 Bcf/d, despite Orca LNG's submission that the full approved LNG export volumes would be unlikely to materialize.

The NEB was satisfied that the resource base in Canada was sufficiently large to accommodate the reasonably foreseeable Canadian demand, as well as the LNG exports proposed by Orca LNG. The NEB also noted that the evidence provided by Orca LNG was generally consistent with the NEB's own market monitoring information, and further agreed with Orca LNG that not all LNG export licences issued by the NEB will be used to their full extent. On this basis, the NEB found that Orca LNG's projections were reasonable, and that there would be sufficient resources to meet Canadian demand plus the forecasted level of LNG exports.

Orca LNG requested an annual 15 percent tolerance to the amount of LNG exported in a given 12-month period, and also requested a sunset clause whereby the licence would expire ten years from the date of issuance if exports have not commenced on or before that date.

The NEB approved the requested 15 percent annual tolerance, noting that the maximum term quantity of the licence is inclusive of the 15 percent tolerance amount. The NEB also accepted the request for a sunset clause, noting it to be generally consistent with NEB practice.

The NEB approved the requested point of export of LNG at the outlet of the loading arm of a proposed terminal located near Prince Rupert, British Columbia.

The NEB issued the licence to Orca LNG, subject to approval of the Governor in Council, having found that the quantity of gas to be exported by Orca LNG would be surplus to Canadian needs.

TransCanada PipeLines Limited King's North Connection Pipeline Project (Reasons for Decision GHW-001-2014)
Pipeline Application

On August 15, 2014, TransCanada PipeLines Limited ("TransCanada") requested:

(a) Approval to construct and operate the King's North Connection Pipeline Project (the "Project"), consisting of a 914.4 mm pipeline of 11 km in length, with two-tie-in valves and associated facilities; and

(b) A Transportation by Others ("TBO") arrangement on Enbridge Gas Distribution Inc.'s ("EGDI") Segment A pipeline.

The Project proposed to connect EGDI's Albion station to the existing TransCanada Line 200-2, 914.4 mm pipeline in the Toronto area. The Project would act as a partial loop of TransCanada's Mainline facilities between the Parkway and Maple Compressor Station, in concert with the TBO.

The Project is also a product of the 2013-2030 Mainline Settlement Agreement approved in Reasons for Decision RH-001-2014. As such, no accompanying tolls and tariff application was made. The Project is underpinned by five requests for 15 years of firm transportation services starting in November 2015, totalling 364,475 GJ/d.

In this decision the NEB provided its reasons for its approval of the Project, which it had previously granted by way of letter decision on June 2, 2015.

Routing

TransCanada noted that the Project would pass through congested urban areas, major highways, high-voltage transmission lines and environmentally sensitive areas, and would require a 30 metre safety zone throughout the proposed route. TransCanada's proposed route would cross Highway 407, and run parallel to a portion of Highway 427, terminating at the tie-in to the TransCanada 200-2 line. In order to mitigate conflicts with other utilities, TransCanada proposed varying the size of the Right of Way, and using a variable depth to accommodate existing or proposed utilities.

Several landowners and municipal authorities expressed concerns about impacts of the Project on accessibility, and utility access, noting that the safety zone encroached over the Ontario Ministry of Transportation's Rights of Way.

The NEB noted that the parties were able to arrive at negotiated solutions for any conflicting infrastructure access areas, and commended the parties for their approach. The NEB also found that the proposed routing solutions, including horizontal directional drilling, would be in compliance with applicable regulations, and with CSA Z662: Oil and Gas Pipeline Systems ("CSA Z662"). The NEB held that, given the number of constraints in the area, TransCanada's proposed route represented the best balance of construction feasibility, land fragmentation, and avoidance or paralleling of existing or planned infrastructure.

The NEB further determined, after review of TransCanada's environmental assessment, that TransCanada's proposed environmental protection procedures and mitigation, in combination with the conditions imposed, would ensure that the Project would not likely cause significant adverse environmental effects.

Consultation

TransCanada submitted that its consultation program sought to identify stakeholders potentially affected by the project within a 1 km radius of the proposed route. Preliminary consultations took place in November 2013 and January 2014, detailed project information was mailed to stakeholders in July 2014, and information respecting alternative routes was provided in the autumn of 2014.

The NEB noted the ongoing efforts of TransCanada and stakeholders in respect of land issues, and infrastructure access, and held that it expected TransCanada to continue working with stakeholders to reasonably address their concerns. The NEB also imposed Condition 11, which would require TransCanada to create and maintain a record of project related complaints and concerns by stakeholders, including regional and municipal governments as well as landowners for a period of five years. The NEB otherwise held that the design and implementation of TransCanada's public consultation program was adequate given the scale and setting of the Project.

With respect to Aboriginal matters, the Mississaugas of the New Credit First Nation ("MNCFN") participated as an intervener, and the Conseil de la Nation huronne-wendat participated as a commenter.

TransCanada stated that it engaged with five other Aboriginal groups in addition to those participating in the proceeding, including email and telephone communications to identify any outstanding concerns, and hosted an open house. TransCanada noted that it would continue its Aboriginal engagement process throughout the lifecycle of the Project. TransCanada stated that the Project would be located within the boundaries of the Upper Canada Treaties, 1764-1836, and did not cross any lands defined as reserve lands or designated for reserve status. However, TransCanada noted that the Project would traverse the traditional territories of a number of groups, including the MNCFN. TransCanada stated that it was not aware of any traditional activities being practiced within the areas, given its urban setting.

MNCFN raised concerns that the Project could harm culturally and environmentally sensitive sites within its traditional territory, and requested to participate in TransCanada's environmental and archaeological assessments. The Conseil de la Nation huronne-wendat submitted a similar request.

TransCanada stated that each group provided archaeological monitors throughout studies on the Project, and that TransCanada committed to capacity funding agreements with both the MNCFN and the Conseil de la Nation huronne-wendat.

The NEB held that Aboriginal groups were provided with sufficient information about the Project, and noted TransCanada's commitment to continue working with each of the groups to address any concerns raised throughout the lifecycle of the Project. The NEB held that given the nature of the Project area, any potential impacts on the rights and interests of Aboriginal groups would likely be minimal, and would be appropriately mitigated. The NEB further imposed Condition 3 on TransCanada, which requires TransCanada to capture and report on any Project commitments in relation to the Project.

Economic Impact and Feasibilities

TransCanada submitted that the Project was expected to generate a demand for goods, services and workers which would generate business and employment income in the area. TransCanada also committed to maximize local procurement where practical, and to implement a community investment plan in the municipality of Vaughan.

TransCanada submitted that the Project was needed to meet new service requests. Without the Project, TransCanada projected a shortfall of capability of 306 TJ/d. TransCanada held a new capacity open season ("NCOS") for the Project, leading to precedent agreements with Union Gas Limited and Gaz Métro Limited Partnership taking up the full capacity of the Project.

The municipality of Vaughan raised concerns in respect of lost tax revenue from areas that would not be developed due to the pipeline Right of Way.

The NEB held that it was satisfied that TransCanada identified and considered the socio-economic impacts of the Project, and proposed suitable mitigation. On the subject of lost tax revenues, the NEB found that there was insufficient evidence to indicate that the Project would result in lower future tax revenues for the municipality of Vaughan.

The NEB determined that the NCOS was conducted in a fair and transparent manner and found that there was sufficient commercial support for the Project, given the precedent agreements for the full capacity of the line. The NEB further noted that the Project would address an existing bottleneck on the Mainline system, and would improve access to growing and competitive sources of natural gas for shippers on the Mainline.

Emergency Response

TransCanada submitted that the Project facilities would be incorporated in TransCanada's emergency management system, and would be compliant with applicable regulations, as well as CSA Z731: Emergency Preparedness and Response. For the construction phase, TransCanada committed to develop an emergency response plan in the event of sediment releases or spills during the construction of trenchless crossings, such as horizontal directional drilling.

The NEB found that the measures proposed by TransCanada for emergency preparedness were appropriate. The NEB also noted that it expects TransCanada to consult with affected parties and make available to them all relevant information consistent with that which is specified in its emergency procedures manual.

Order

As reported in our June 2015 issue, the NEB issued Order XG-T211-027-2015 and the associated conditions to approve the Project. The NEB also granted TransCanada's request for exemptions from Section 30(1)(a) and 31 of the *National Energy Board Act.*