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DECISIONS

REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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

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

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ALBERTA ENERGY REGULATOR

Bashaw Oil Corporation – Applications for Proximity Critical Sour Wells Nisku Formation, Drayton Valley Area (2018 ABAER 002)
Well Applications – Water Act – Applications Denied

In this decision, the AER provided its reasons for denying Bashaw Oil Corp.'s ("Bashaw") well applications 1842705, 1851246, and 1851250 and *Water Act* application 001-00400207 (the "Applications"), without prejudice to any future application.

The AER explained that section 15 of the *Responsible Energy Development Act* ("*REDA*") and section 3 of the *REDA General Regulation* require the AER to consider:

(a) the social and economic effects of the proposed wells;

(b) the effects of the proposed wells on the environment;

(c) the interests of landowners; and

(d) the impacts on a landowner as a result of the use of the land for the proposed wells.

Landowner Consultation Insufficient

The AER found that Bashaw's consultations with the landowners were inadequate for the Applications.

The AER heard landowner accounts that it found troubling, especially for consultation for proximity critical sour wells. Bashaw did not meet with the landowner whose land was adjacent to the well site. Bashaw was non-responsive to legitimate questions from others.

The AER noted that:

(a) Applicants are required by Directive 056 to implement an effective consultation plan before filing an application; and

(b) Directive 056 requirements are considered the minimum acceptable consultation and notification for routine applications and the starting point for effective participant involvement, which is expected to take place throughout the life cycle of the project.

The AER found that:

(a) Bashaw chose to complete the majority of its participant involvement program after it submitted the well applications to the AER, by its own admission due to the perceived opposition from landowners;

(b) while consultation does not have to satisfy concerns, the parties should be respectful, responsive, and responsible; and

(c) Bashaw's consultations failed to meet this expectation.

The AER explained that the consultation process facilitates the raising of issues so that proponents can understand concerns and address them effectively. Directive 056 provides that "in some areas of the province, public expectations regarding personal consultation and notification may be higher than in others." In this case, the AER panel found that public expectations regarding personal notification and consultation were higher in the area where the wells were proposed to be located. The AER rejected Bashaw's argument that it exceeded the minimum requirements, finding that Bashaw's consultation did not meet the spirit or intent of Directive 056. The AER found that Bashaw's decision to do the minimum was not appropriate in these circumstances given the landowners' concerns and the potential risks of a high-consequence incident.

Adequacy of Emergency Response Plan

Bashaw filed a basic Emergency Response Plan ("ERP") with the Applications and indicated that it planned to work out site-specific details after it received its licences from the AER. The AER found Bashaw's ERP to be deficient because it lacked sufficient site-specific information.

AER Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry ("Directive 071") requires an applicant to include as part of its application an ERP. An ERP must address three core principles:

(a) what could go wrong, who could be impacted, and who needs to be involved;

(b) what resources and training are needed; and

(c) whether the licensee could respond during a real incident.

Licensees must ensure that they are fully prepared and capable of responding to any level of emergency, considering the site-specific area terrain and demographics. The AER must be confident that an applicant has a sufficient level of preparedness and the capability to implement its ERP.

For the reasons summarized below, the AER found that Bashaw failed to satisfy the panel that it was capable of planning and carrying out a complex evacuation that would be required in the case of an uncontrolled H_2S release.

Risk of H_2S Release

The AER explained that in the event of an uncontrolled release of H_2S from a critical sour well, there would commonly be time to ignite the release so that no H_2S would escape the well pad. However, in a situation where the well could not be ignited, and an H_2S plume escaped the immediate area of the well site, people in the emergency planning zone ("EPZ") would be directed to shelter in place until the plume dissipated. For those sheltering in place, it is unlikely that they would be exposed to H_2S at a concentration that could seriously injure them. The plume would disperse, and the H_2S concentrations would not likely be at a high enough level to cause injury from the short-term exposure.

The AER noted multiple specific regulatory requirements for drilling a critical sour well to prevent an H_2S release, including requirements for well design, proper operational drilling practices, and safety precaution measures.

The AER explained a full-scale prolonged blowout of a sour well would be a high-consequence incident with the potential for serious injuries or deaths. While a remote possibility, in the event of an uncontrolled release of H_2S, an area evacuation would have to be carried out.

The AER concluded the ERP lacked sufficient site-specific information and therefore Bashaw failed to demonstrate a sufficient level of preparedness and the capability to implement its ERP, because:

(a) an evacuation process in the event of a serious incident would be extremely complex and would have to be fluid regarding reacting to the situation at hand;

(b) addressing an incident could be hampered by the complicated circumstances of the residents, frequent poor road conditions in the area, intermittent cell phone coverage, and the area's deep valleys, large hills, and the river valley where people live and engage in outdoor recreational activities;

(c) many of the landowners' concerns, including spotty cell phone coverage, health and mobility issues, evacuation of horses and companion animals, and egress towards the well site were not sufficiently taken into consideration by Bashaw in its ERP;

(d) the fact that a landowner within the egress zone did not know whether she was in the emergency response planning zone suggested that Bashaw had clearly not engaged in effective communications with that individual; and

(e) of its poor consultations, Bashaw did not have a strong enough understanding of the many local challenges that it would face in an emergency situation.

Alternate Egress

The AER found that Bashaw was required, but failed to include in its ERP an alternate egress.

Directive 071 does not explicitly mandate an alternate egress route for proximity critical sour wells and allows for egress through the EPZ. However, applicants must plan for all levels of emergencies and the safe evacuation of people potentially in harm's way. Sometimes applicants may need to go beyond the minimum requirements to ensure public safety, and the AER found that this was such a case.

The AER noted factors, in this case, necessitating an alternate egress road to ensure safe development of the resource:

- The occupants from 26 residences in the EPZ would need to egress towards the well site if required to evacuate.
- The people engaging in outdoor activities east and northeast of the well would not be easily reached or able to shelter in place.
- The local terrain, with its deep valley where the release could potentially flow and stagnate, increases the risk that certain residents may be exposed to H_2S at levels that could cause health impacts. People living northeast of the well site would be particularly vulnerable in this regard, and they are the ones who have no alternative egress route.
- The County, which has jurisdiction over the roads, advised the AER of its concerns about the

problems with the existing roads in certain conditions and that it recommends an alternate egress for the safety of residents and its employees.

Social and Economic Effects

The AER explained that the economic benefits of the project must be weighed against considerations of public safety. Given the safety concerns outlined above, the AER concluded that the risk of safety-related impacts outweighed the economic and social benefits the project might bring.

Conclusion

For proximity critical sour wells, the AER explained that it must ensure that the safety of the public will not be compromised. The AER found that it could not conclude that public safety would be ensured if the licences were to be issued.

Therefore, the AER declined to issue the well licences to Bashaw because to do so would be inconsistent with the AER's mandate to ensure the safe development of energy resources in Alberta.

ALBERTA UTILITIES COMMISSION

ATCO Pipelines – Compliance Application to Decision 22011-D01-2017, 2017-2018 General Rate Application (Decision 22986-D01-2018)
General Rate Application – Compliance Filing

On August 29, 2017, the Commission issued Decision 22011-D01-2017, in which it directed ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd. ("ATCO") to file a compliance application in accordance with the findings and specific AUC directions set out in Decision 22011-D01-2017.

In this decision, the AUC considered ATCO's compliance with:

- Direction 5 regarding Weld Integrity Inspections and Replacements Program ("WIIR Program");
- Directions 11 and 18 regarding pension costs;
- Direction 20 regarding accumulated depreciation balances for Account 496.05 (general plant – equipment – SCADA); and
- Direction 36 regarding removal costs charged to Account 451.00 (underground storage plant) and the continued necessity for any negative net salvage percent.

<u>Direction 5 – Weld Integrity Inspections and Replacements Program</u>

The AUC directed ATCO to remove its 2016 re-inspection costs from its 2017 opening rate base and the forecast 2017 and 2018 re-inspection capital expenditures from its 2017-2018 revenue requirements.

The AUC found that ratepayers should not bear the costs to re-inspect welds that were not properly inspected in the first place. The AUC noted that the costs of the original deficient inspections were being recovered through rates and that it would be unreasonable to permit ATCO to recover re-inspection costs from customers when it could and was pursuing such costs through litigation for the deficient work.

The AUC found that rather than approving ATCO's proposal to recover the costs from customers, and then credit customers for any litigation proceeds obtained, ATCO should recover the costs from the involved radiographic companies and technicians for its own account to the extent that it can do so.

In determining that the WIIR Program capital expenditures should not be included in ATCO's 2017 opening rate base and 2017-2018 revenue requirements, the AUC considered whether these costs were prudently incurred and whether ATCO's forecast costs were reasonable, and therefore borne by customers.

The AUC previously set out the test for prudence or reasonableness of costs in Decision 2001-110:

> … a utility will be found prudent if it exercises good judgment and makes decisions which are reasonable at the time they are made, based on information the owner of the utility knew or ought to have known at the time the decision was made. In making decisions, a utility must take a fair return.

In assessing the prudence of the inspection and repair costs, the AUC considered:

(a) ATCO's actions since discovering the deficient radiographic inspections, including its plan and forecasts to assess and remedy the deficiencies;

(b) whether it was reasonable, in the circumstances, for ATCO not to have discovered the deficient radiographic inspections until 2015; and

(c) whether all of the costs associated with assessing and remedying deficiencies from 2008 to 2015 were prudent and reasonable given all of the circumstances.

The AUC found that:

(a) ATCO should have established some quality control measures to ensure work was being properly performed and completed by its contractors, such as radiographic inspection companies and technicians;

(b) greater oversight of the radiographic inspections/inspectors could have ensured a more reliable process and mitigated the risk of seven years of deficient inspections and welds being placed in service;

(c) it was not reasonable for this type of deficient work to have continued for seven years or more without being discovered; and

(d) better processes could have been and should have been in place.

Direction 11 and 18 - Pensions Costs

The AUC found that ATCO complied with directions 11 and 18 of Decision 22011-D01-2017.

Decision 22011-D01-2017, Direction 11, stated:

> 257. The Commission directs ATCO Pipelines to incorporate the findings of Decision 21831-D01-2017 for all pension costs and COLA [cost-of-living adjustment] into its compliance filing to this decision. Based on Decision 21831-D01-2017, the Commission does not approve the placeholders for a pension COLA adjustment from 50 per cent to 100 per cent.

Decision 22011-D01-2017, Direction 18, stated:

> 365. … The Commission directs ATCO Pipelines to update its placeholder schedule for pension COLA costs in its compliance filing according to Decision 21831-D01-2017.

Given that Decision 21831-D01-2017 approved COLA at 50 percent, which was the percent assumed by ATCO in its original application, no adjustments were required to the forecast pension amounts. ATCO, in response to the AUC's directions, removed the COLA placeholder from the placeholder schedule.

Direction 20 - Accumulated Depreciation Balances for Account 496.05 (General Plant – Equipment – SCADA)

The AUC found that ATCO complied with Direction 20 and denied the Office of the Utilities Consumer Advocate's ("UCA") request to eliminate depreciation expense for Account 496.05. The AUC accepted ATCO's explanation that the restated opening 2012 Account 496.05 balance was a result of a prior period adjustment of $1,584,000 (debit) to accumulated depreciation.

Notwithstanding the above, the AUC found that:

(a) ATCO failed to adequately address this issue in Proceeding 22011 and this compliance proceeding; and

(b) ATCO's unresponsiveness to interveners' concerns did not meet the AUC's expectations concerning record development nor did it contribute to an efficient and better understanding of the issues considered in Decision 22011-D01-2017 or this decision.

The AUC noted, however, that ATCO explained the cause of confusion in its reply argument and apologized to the UCA and the AUC for what it indicated was an unintentional oversight.

Direction 36 - Regarding Removal Costs Charged to Account 451.00 (underground storage plant) and the Continued necessity for any Negative Net Salvage Percent

The AUC confirmed that Direction 36 remained outstanding, to be addressed in full in ATCO's next depreciation study.

In making this finding, the AUC set out that in Decision 22011-D01-2017, the AUC approved a net salvage percent of -10.0 for Account 461.00 – transmission plant – land rights. However, the AUC directed ATCO in its next depreciation study to discuss the nature of the proceeds and removal costs being charged to this account and the continued necessity for any negative net salvage percent.

In its response to Direction 36, ATCO Pipelines reiterated there was no change to its depreciation expense as a result of the Commission approving a net salvage percent of -10.0 for Account 461.00 – transmission plant – land rights as filed. However, in response to Commission IR55 and again in argument, ATCO confirmed that the latter part of Direction 36 remained outstanding. ATCO submitted that it would "discuss the nature of the proceeds and removal costs being charged to this account and the continued necessity for any negative net salvage per cent" in its next depreciation study.

EPCOR Energy Alberta GP Inc. – 2018-2021 Energy Price Setting Plan (Decision 22357-D01-2018)
Regulated Rate Option – Energy Price Setting Plan

As a regulated rate option ("RRO") provider, EPCOR Energy Alberta GP Inc. ("EEA") is required to file monthly energy rates with the AUC. These monthly energy rates are determined under the *Electric Utilities Act* ("*EUA*"), in accordance with the *Regulated Rate Option Regulation* (the "*RRO Regulation*"), and the applicable AUC approved energy price setting plan ("EPSP").

In this decision, the AUC considered EEA's application requesting approval of a proposed EPSP for the term of May 1, 2018, to April 30, 2021.

Decision Summary

The AUC approved EEA's request to procure full-load products and fixed block products using a descending clock auction format.

EEA's Current EPSP

The AUC explained that the monthly energy charges under EEA's current EPSP are composed of the following elements:

- base energy charge;
- reasonable return compensation;
- Alberta Electric System Operator ("AESO") trading charges;
- Natural Gas Exchange ("NGX") trading charges and transaction fees;
- AESO collateral costs;
- backstop collateral costs;
- NGX collateral costs;
- external EPSP development and regulatory costs;
- other credit costs;
- retail adjustment to market (RAM) costs;
- uplift charges (UC);
- commodity risk compensation; and
- other risk compensation.

The AUC noted that, typically, the base energy charge, reasonable return, commodity risk compensation and other risk compensation are the most contentious components of the EPSP, as was the case in this proceeding.

Regarding the base energy charge under EEA's current EPSP, the AUC explained that:

(a) The base energy charge reflects the value of the forward market energy products acquired by EEA;

(b) under its current EPSP, EEA procures 7X24 flat volume blocks in 10 megawatt (MW) block sizes, and it procures 7X16 peak volume blocks in 5 MW block sizes;

(c) the 7X24 flat volume product means the volumes in MW for an energy product for all hours in a day, Monday through Sunday inclusive; and

(d) the 7X16 peak volume product means the volumes in MW for an energy product for hours eight through 23 in a day Monday through Sunday inclusive.

Concerning EEA's procurement of energy products under its current EPSP, the AUC explained that:

(a) EEA procures its energy products for each month through six auction sessions, plus one contingency auction session, if required;

(b) the auctions sessions are spread out, approximately equally across the 120-day allowable price implementation period related to procurement of energy for a given month; and

(c) EEA designed its current auction to follow a random close format, where the initial price input is confidentially determined for each auction session, referred to as the seed price.

To determine monthly charges under EEA's current EPSP:

- The volume-weighted average price of the forward market energy products acquired during the 120-day procurement period is used as the starting point to set the base energy charges for a given month.
- The total energy portfolio cost for the month is determined using the cost and associated volumes of all the forward market energy products acquired for a given month, which is then separated into an on-peak energy portfolio cost and an off-peak energy portfolio cost.
- From this information, a weighted average on-peak price per MWh and a weighted average off-peak price per MWh is determined.
- For each rate class, the weighted average on-peak price per MWh is multiplied by the ratio of a rate class's on-peak forecast load to its total forecast load.
- The resulting figure is added to the product of the weighted average off-peak price per MWh and the ratio of the rate class's off-peak forecast load to its total forecast load.
- The resulting figures are the base energy charges in $/MWh for each rate class in the service area.

The AUC explained that this methodology results in the rate classes with a higher ratio of on-peak forecast load to total forecast load having a higher base energy charge since the cost of on-peak forward market energy products is greater than the cost of off-peak forward market energy products.

Regarding risk compensation under the current EPSP, the AUC explained that section 6(1) of the *RRO Regulation* requires that:

(a) the AUC approve a risk margin that provides the owner with just and reasonable financial compensation for the risks described in section 5 of the *RRO Regulation*; and

(b) this risk compensation components to be distinguished from and separate to the reasonable return compensation component.

The need for risk compensation arises from:

(a) Price Risk: Differences between the cost of the forward market energy products acquired by EEA to meet its forecast load, and the actual cost of electricity used by EEA's customers; and

(b) Volume Risk: Differences between the volume of electricity EEA acquires in advance of the month and the actual volume of electricity used by EEA's customers during the month.

These risks result from price and volume differences on an expected versus actual basis, and correspondingly, net systematic losses or gains for EEA. The AUC explained that the systematic losses, can be significant, and EEA receives commodity risk compensation for these losses.

In addition to commodity risk compensation, EEA also receives other risk compensation. The AUC explained that EEA receives other risk compensation for being exposed to two types of cost recovery risk, namely:

(a) the risk caused by the differences between actual and forecast electricity sales, given that EEA charges monthly RRO rates based on forecast electricity sales; and

(b) the risk that EEA's actual operating costs will be different from its forecast operating costs. The amount approved for other risk compensation in its current EPSP is $0.07/MWh.

<u>EEA's proposed 2018-2021 EPSP</u>

EEA proposed several changes to the 2018-2021 EPSP from its current EPSP, largely related to the forward market energy products procured, the auction format, the number of auction sessions, the calculation of the base energy charge and the calculation of the commodity risk compensation.

For the 2018-2021 EPSP, EEA proposed acquiring the following blocks of forward market energy products:

- 7X24 flat volume blocks in 5 MW block sizes;
- 7X16 peak volume blocks in 5 MW block sizes;
- a full-load product; and
- changes from the current EPSP including a reduction in the block size of the 7X24 peak volume blocks, from 10 MW to 5 MW, and the addition of the full-load product.

EEA explained that the full-load product would be procured in strips (full-load strips or full-load strip products). EEA expected that the full-load strips would average about 4 MW in size. The actual size of each full-load strip would not be known until the month concluded and the actual hourly load, including losses, was determined.

EEA proposed that approximately 50 percent of the forward market energy products would be full-load strips and the remaining 50 percent would be fixed block products. EEA would simultaneously procure three forward market energy products for each month through a series of four scheduled auction sessions, plus up to two contingency auction sessions (a change from the current six auction sessions, plus one contingency session).

EEA proposed using a descending clock auction format (discussed below). Two components of the descending clock auction would be completed on a confidential basis: (1) the starting price methodology, and (2) the competitiveness assessment and volume reduction methodologies.

Currently, EPSP's base energy charge is determined using the acquisition prices for the flat and peak block products. EEA proposed that under the 2018-2021 EPSP, only the volume-weighted average price of the full-load strip products acquired in all auction sessions during the 120-day allowable price implementation period would be used to determine the base energy charges for the month.

EEA also proposed to include a backstop charge. The backstop charge is a $/MWh charge related to costs of having a backstop supplier for electricity in case EEA cannot acquire all of its forward market energy products through its auction sessions. The backstop charge component to the proposed 2018-2021 EPSP includes a retainer fee, whereas, the backstop used in the current EPSP does not.

RRO Regulation

The AUC first considered whether the provisions of the *RRO Regulation* permitted EEA to acquire full-load strip products for approximately 50 percent of the forward market energy products it procures and to determine the value of its commodity risk compensation using the price of these full-load products.

The AUC specifically considered three sections of the *RRO Regulation*:

(a) Section 5(2): compensation may only cover risks to which the owner is directly exposed;

(b) Section 6(1)(f): risk of acquisition remains with the owner; and

(c) Section 6(1)(b): reasonable return must be allowed for, and it must not consider risk compensation.

The AUC concluded that EEA's proposed commodity risk compensation methodology would not result in EEA receiving excess reasonable return over and above the amount explicitly awarded.

Section 5(2): Risk compensation may only cover risks to which the owner is directly exposed

Section 5(2) of the *RRO Regulation* states that "The risk margin may only cover risks to which the owner is directly exposed and may not include risks that are borne by a person other than the owner."

The AUC concluded that EEA's proposed commodity risk compensation methodology was not contrary to Section 5(2) because:

(a) the suppliers of that product would bear the commodity risk associated with the full-load product, and the price of the commodity risk associated with the full-load product would be paid to the suppliers of that product, not to EEA;

(b) EEA was not requesting risk compensation, i.e., a risk premium, over and above what suppliers were building into the price for the full-load product; and

(c) EEA would appropriately only receive compensation for the commodity risk to which it is exposed associated with the fixed block products.

Section 6(1)(f): Procurement risk of acquisition remains with the owner

The AUC found that even though EEA proposed to acquire full-load product for half its monthly load, it would remain responsible for the procurement of all the energy required to satisfy its monthly load obligations. The financial risk of satisfying all of its monthly load ultimately remained with EEA, should energy not be supplied through either full-load strip products, or fixed block products, or if the backstop mechanism was triggered.

The AUC concluded that EEA's proposed commodity risk compensation methodology did not violate section 6(1)(f). The AUC rejected an intervener's argument that by offering a different forward market energy product (the full-load product) the owner's risk was transferred to someone other than the owner, contrary to the RRO Regulation.

In making these findings, the AUC noted:

(a) Owner is a defined term under *RRO Regulation* and includes an RRO provider, such as EEA; and

(b) Neither "procurement" nor "acquisition" is defined in the *RRO Regulation* or the *EUA*. Nor were there any specific provisions to inform the Commission on the approval of the EPSP "in a manner that ensures that procurement risk of acquisition remains with the owner."

Section 6(1)(b): Reasonable return must be allowed for and it must not consider risk compensation

The AUC concluded that EEA would not receive excess reasonable return due to its proposed methodology for commodity risk compensation and therefore did not contravene section 6(1)(b)(ii). In making this finding, the AUC noted that:

(a) the only difference in the prices of full-load and fixed block products would be the cost of the additional volume risk associated with full-load products;

(b) to the extent that a supplier builds additional return into the amount it needs in order to be willing to provide the quantity of its full-load product bid, an amount that is above its forecast cost of the additional risks it will be facing, that supplier would be disadvantaged, all else being equal, versus another supplier with the same costs who does not price-in such additional returns;

(c) over time, this supplier would determine that its strategy of including additional return was suboptimal, because of a continued lack of success from offers into the full-load product auctions and an effect of competition. This concept supports the position that the cost of full-load products will not contain excess reasonable return in relation to fixed block products;

(d) arbitrage opportunities would be addressed by the competitive properties (including the competitiveness assessment step) of its proposed auction process; and

(e) the competitive nature of the auction process should lead to full-load product auction prices that differ from the fixed block product auction prices, only by the forecast value of the additional risk faced by the suppliers of the full-load product.

<u>Energy Acquisition Process</u>

Regarding the ESPS energy acquisition process, the AUC considered EEA's proposed:

(a) descending clock auction format;

(b) contingency plan in case the descending clock auction format and the procurement of full-load product did not function as intended; and

(c) a backstop mechanism for supply of forward market energy products if it cannot acquire all of its required volumes through the descending clock auction format.

Descending Clock Auction Format

The AUC approved EEA's proposed use of a descending clock auction format for its 2018-2021 EPSP.

In approving the change in an auction format (from a random close to a descending clock auction), the AUC found that:

(a) on balance, the descending clock auction design format was not expected to discourage participation in such auctions for the 2018-2021 EPSP due to its complexity; and

(b) the descending clock auction design format had a reasonable chance of being implemented successfully by EEA in Alberta, based on successful experiences in other jurisdictions using the descending clock auction format for the procurement of multiple products.

The AUC agreed with EEA that the descending clock format better ensured that competitive forces inherent in the determination of forward hedge prices for the full-load product would capture the proper value for commodity risk compensation. As a result, instead of having an administratively-determined value for commodity risk compensation, market participants engaged in a competitive, descending clock auction would determine this value.

Requested Flexibility

The AUC granted EEA's requested flexibility to make limited adjustments to certain auction parameters to ensure the ongoing competitiveness of its auctions, with one modification for the auction round lengths as discussed below.

EEA stated that parameters might require adjustment based on EEA's experience with the descending clock auction in the context of the Alberta electricity market, as this would be the first time that such a procurement would be used in Alberta. Such adjustments were necessary to improve the ability of the descending clock auction process to attract participation that would produce competitive results, or if changes in the Alberta electricity market necessitated adjustments.

Backstop Mechanism

The AUC approved EEA's proposed backstop mechanism except for including an amount of $2.50/MWh for fixed risk compensation as part of the backstop commodity risk compensation mechanism.

Considering the possible changes in the Alberta wholesale electricity market over the EPSP term, the structure of the proposed EPSP and the new descending auction design, the AUC preferred EEA's proposal in which a backstop supply arrangement would be established at the outset of the EPSP's term. The AUC found that such a plan reduces the uncertainty associated with procuring electricity for the RRO if the regular and contingency auction sessions were unable to obtain sufficient supply.

<u>Risk Compensation</u>

The AUC, by extension, also approved EEA's proposal for pricing commodity risk compensation as set out in its 2018-2021 EPSP. The AUC found EEA's proposed market-based commodity risk compensation methodology to be a logical extension of its proposal for procuring full-load products and fixed block products simultaneously through the use of a descending clock auction.

The AUC found that the winning prices for the full-load product and the fixed block products would incorporate each suppliers' cost for bearing the risk associated with each product. The AUC agreed with EEA's proposal to derive the commodity risk compensation by providing the market the opportunity to both incur and price the risk and use its appropriate tools to manage that risk.

With market-determined prices, the AUC considered that the difference between the price for the full-load product and the fixed block products would compensate EEA for both price and volume risk.

On this basis, the AUC found that EEA's proposed commodity risk compensation methodology would result in a commodity risk compensation that is market base and would reflect the risk differential associated with full-load products.

Reasonable Return

The AUC found that under EEA's proposed methodology, the reasonable return percentage for a subsequent year would be more than the 1.50 percent that EEA has requested, even if none of the parameters between years changed. However, using the same assumptions and the AUC's methodology, the resulting after-tax reasonable return percentage for the subsequent year would be exactly 1.50 percent. This exercise supported the AUC's finding that the methodology in Decision 2941-D01-2015 was the proper manner to determine the reasonable return.

The AUC denied the methodology proposed by EEA for the annual calculation of the reasonable return.

EEA receives a reasonable return for its obligation to provide service. The reasonable return compensation is a legislated requirement under section 6(1)(b) of the *RRO Regulation*.

EEA's current ESPS reasonable return compensation was \$2.51/MWh (after-tax), determined as part of the generic RRO proceeding held during 2014/2015. The \$2.51/MWh was calculated as 1.50 percent of EEA's energy revenues, non-energy revenues and distribution and transmission revenues, less local access fees and municipal franchise fees, for the year 2013. This after-tax amount was approved for the entire term of the current EPSP and, therefore, has remained static at \$2.51/MWh.

EEA based its proposed reasonable return for 2018-2021 on the methodology approved in its current EPSP but with the opportunity to update the reasonable return each July to reflect the energy revenues, non-energy revenues and distribution and transmission revenues, less local access fees and municipal franchise fees, for the previous year.

The AUC directed EEA, as part is compliance filing, to revise its reasonable return calculation methodology to be the same as the methodology in Decision 2941-D01-2015.

Order

The AUC approved EEA's EPSP, subject to the findings and directions set out the decision.

The AUC directed EEA to submit a compliance filing, to reflect certain changes required to the 2018-2021 EPSP.

Bulletin 2018-04: Roles and Responsibilities of the Alberta Utilities Commission and Alberta Environment and Parks for Applications to Construct and Operate Wind and Solar Power Plants

Wind and Solar Projects – Alberta Environment and Parks

In this bulletin, the AUC announced the issuance of a roles and responsibilities document, jointly developed by the AUC and Alberta Environment and Parks ("AEP") (the "Roles and Responsibilities Document").

In the Roles and Responsibilities Document, the AEP and the AUC jointly confirmed their respective roles and responsibilities for wildlife management matters in the approval and monitoring of wind and solar power plants in Alberta, including the following:

- AEP is responsible for the overall management and regulation of wildlife in Alberta. AEP's responsibility includes establishing policies, directives, guidelines and similar administrative procedures (collectively, wildlife policies) under the *Wildlife Act and the Environmental Protection and Enhancement Act*, including responsibilities for the designation, protection, and recovery of wildlife, including endangered animals and other sensitive species, and wildlife habitat.
- The AUC is responsible for approving the construction and operation of wind and solar power plants under the *Hydro and Electric Energy Act* and the *Alberta Utilities Commission Act*. Its approval process includes considering the potential impacts on wildlife and wildlife habitat. The approvals, permits, and licences issued by the AUC may prescribe conditions relating to wildlife protection consistent with the environmental legislation and wildlife policies. The responsibility for surveillance and enforcement of those conditions rests with the AUC, which includes reviewing any advice provided by AEP.

The Roles and Responsibilities Document is available on the AUC website.

Bulletin 2018-05: Amended Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments
Rule 007 – Wind and Solar Projects – Alberta Environment and Parks

In this bulletin, the AUC announced minor amendments to Rule 007 to reflect certain aspects of the Roles and Responsibilities Document (summarized above). The AUC stated that the most notable change is the inclusion of wildlife referral reports prepared by AEP staff in the applications submitted by prospective wind and solar power plant proponents.

The Commission approved the amendments on March 21, 2018, with an effective date of April 2, 2018. The AUC considered the amendments to be minor and were made without stakeholder consultation.

The amended rule and a blacklined version of the rule may be found in the Rule-related consultations section of the AUC website.

NATIONAL ENERGY BOARD

NEB Examination to Determine Whether to Undertake an Inquiry of the Tolling Methodologies, Tariff Provisions and Competition in Northeast British Columbia – Examination Decision
Examination Decision – Tolling Methodologies in Northeast BC

On January 26, 2017, the NEB Chairperson authorized Board Member L. Mercier to initiate an examination to determine whether an inquiry of the tolling methodologies or tariff provisions of one or more of the Group 1 NEB-regulated natural gas pipeline companies operating in Northeast BC was warranted.

In this NEB letter decision, the NEB determined that it would not hold an inquiry, because:

(a) doing so would introduce undue uncertainty to the Northeast BC supply basin;

(b) an inquiry might not effectively resolve the issues; and

(c) the NEB's established processes – including Filing Manual revisions and upcoming toll applications – were better suited to address these potential issues.

Although the NEB declined to hold an inquiry, it found that it was necessary to review the tolling methodologies of NOVA Gas Transmission Ltd. ("NGTL") and Westcoast Energy Inc. carrying on business as Spectra Energy Transmission ("Westcoast"). The NEB wants to ensure adherence to established tolling principles, fair competition and efficient infrastructure development in Northeast BC. The Board found that capital expansion and depreciation policies were closely interrelated in this context and that reviewing these policies was also required.

Concerning Alliance Pipeline Ltd. ("Alliance"), the NEB held that:

> The Board does not require additional information from Alliance for the purposes of this Examination, given the recent approval of its New Services Offering proposal. The New Services Offering that Alliance has recently implemented places the volume/revenue risk and the preponderance of cost risk on the pipeline. Firm shippers on Alliance accept the risks associated with their contracting decisions and the utilization levels of their contracted services. In addition, the capital cost of new interconnections and facility expansions are paid for by the requesting party(ies) receiving the benefits and not by existing shippers. This reflects a stand-alone tolling methodology and provides a direct link between risks/costs borne by parties requesting new infrastructure and the benefits received by these parties.

<u>Background</u>

NGTL, Westcoast, and Alliance (the "Pipeline Companies") are all Group 1 NEB-regulated natural gas pipeline companies. The Pipeline Companies compete for customers within the resource-rich gas formation in Northeast BC, vying to attract shippers seeking to transport gas produced in that area to market on the competing Pipeline Companies respective systems. Each of the Pipeline Companies operates under distinct tolling methodologies and tariff provisions.

<u>Other Processes to Consider Issues</u>

Filing Manual Revisions

To ensure issues related to fair competition are addressed in future applications, the NEB stated that it would consider revisions to its Filing Manual. For example, modifications could include:

(a) Changes to filing requirements regarding notification of commercial third parties; and

(b) Additional filing requirements for facility extension applications using the pipeline's existing toll methodology including requirements that an applicant: (i) address whether the project could proceed on a stand-alone basis; and (ii) justify rolled-in tolling treatment for proposed facilities, including quantification of costs and benefits.

The Board stated that any such revisions would be developed through the NEB's established process for Filing Manual revisions, which would include industry consultation.

Upcoming Toll Applications

To assess the potential issues regarding competition between NGTL and Westcoast, the NEB found that additional information concerning each company's toll methodology, capital expansion policy and depreciation policy was required. The Board determined that it would consider this information in each company's respective 2019 final tolls application.

<u>Boards Concerns Regarding NGTL Tolling Methodology</u>

The Board found that whether NGTL's tolls adhere to the principles of cost causation and economic efficiency was an issue. The NEB's expressed concerns about NGTL's existing tolling methodology included the following:

- NGTL's current toll methodology does not appropriately recognize changes to system usage.
- Most of the contracts underpinning new extensions on the NGTL System are for a shorter duration than the extension facilities' depreciable life.
- Inefficient use of existing system infrastructure can result if system extensions are not tolled appropriately.
- If NGTL's tolls do not appropriately respect the user-pay principle, then NGTL will be afforded a competitive advantage in seeking to extend its system into Northeast BC.
- NGTL's criteria for system extensions is also an issue, given that NGTL's decisions to construct facilities, based on those criteria, may result in the underutilization of extensions.

The NEB noted that in the Komie North (GH-001-2012), Towerbirch (GH-003-2015) and North Montney (GH-001-2014) applications as well as this examination, parties expressed concerns that NGTL's toll methodology may be providing it with an unfair competitive advantage to expand into Northeast BC. Other parties raised concerns that NGTL's significant capital expenditures have increased system costs and risks.

The Board found that, to date, NGTL tolling had not caused any significant underutilization on the Westcoast system, noting Westcoast's system being fully contracted and recently expanded. The Board acknowledged the risk that such effects could occur in the future.

<u>Board's Concerns Regarding Westcoast Tolling Methodology</u>

The NEB noted that, while Westcoast's toll methodology and system expansions had not faced the same level of scrutiny as NGTL's, some of the same concerns regarding adherence to tolling principles were present. Like NGTL, for Zone 3 of its system, Westcoast rolled-in the cost of system extensions and used postage stamp toll.

The Board noted that Westcoast did not have a written policy regarding capital investments in expansions and extensions. The Board found that Westcoast should develop, document, and file such information. The Board explained that this capital investment policy and accompanying explanation and analysis of Westcoast's depreciation policy and practices would inform the Board of the risks faced by Westcoast and its shippers.

<u>Directions to NGTL and Westcoast</u>

The Board directed NGTL and Westcoast to file information with each company's respective 2019 final toll application. The NEB ordered that this information be filed regardless of whether NGTL or Westcoast reached a negotiated settlement with its shippers.

NEB Direction to NGTL

The NEB directed that NGTL file with its 2019 final toll application the following:

(a) Policies Affecting Capital Spending for System Extensions: An analysis of how NGTL's Tariff and Guidelines for New Facilities ensure appropriate cost accountability for shippers requiring receipt extensions; the analysis should describe any changes proposed to introduce stronger cost accountability for receipt shippers and NGTL. The analysis should also include an overview of how NGTL's Tariff (e.g., Rate Schedule FT-R and Appendix E to NGTL's Gas Transportation Tariff), Guidelines for New Facilities, 2017 Annual Plan, and the Facilities Design Methodology, when applied together with NGTL's toll methodology, contribute to: (a) the optimization of NGTL's extension additions; and (b) the utilization of its existing infrastructure.

(b) Depreciation Policy and Practices:

   (i) an analysis of NGTL's current depreciation study that assesses: how NGTL's system-wide depreciation rates recognize the changing flows on its system and the changing utilization levels on mainline sections/segments;

   (ii) whether the service life for receipt facilities in the depreciation study are aligned with the receipt contract terms so that captive customers are not burdened with responsibility for receipt extensions after receipt contracts have terminated; and

   (iii) the steps that NGTL proposes to take to ensure that the costs of any undepreciated receipt pipeline facilities that are being or will be underutilized or not used will be allocated fairly to shippers and NGTL in the future.

(c) Tolling Methodology and Tariff Provisions: An analysis of NGTL's tolling methodology and tariff provisions that addresses whether the current methodology should be retained for all or part of the existing NGTL system.

NEB Directions to Westcoast

The NEB directed that Westcoast file with its 2019 final toll application the following:

(a) Policies Affecting Capital Spending for System Extensions and Expansion:

(i) Develop, document and file with the Board Westcoast's internal policies, procedures, and practices for capital investments in expansion and extension facilities in Zone 3;

(ii) Provide an analysis of how Westcoast's policies, procedures, and practices ensure appropriate cost accountability for Westcoast and shippers requiring facility additions in Zone 3; and

(iii) Depreciation Policy and Practices: An analysis of the depreciation study that Westcoast is required to file as per TG-003-2016 that assesses:

(i) whether the service life estimates for facilities in Zone 3 in the depreciation study are aligned with the terms (including estimated renewals) of the transportation contracts in Zone 3; and

(ii) if the service life in the depreciation study is greater than the estimated terms of the transportation contracts. When the service life is greater, Westcoast has to explain the steps that Westcoast proposes to take to ensure that the costs of any undepreciated pipeline facilities that are being or will be underutilized or not used will be allocated fairly to shippers and Westcoast in the future.

(b) Tolling Methodology and Tariff Provisions: An analysis of Westcoast's Zone 3 tolling methodology and tariff provisions that addresses whether the current methodology should be retained.

Hydro-Québec TransÉnergie – Permit Application for the Quebec-New Hampshire Interconnection
Electricity Transmission – Application for Interconnection – NEB Act Section 58.11

On 23 December 2016, Hydro-Québec TransÉnergie ("HQT") applied to the NEB pursuant to subsection 58.11(1) of the *National Energy Board Act* ("*NEB Act*"), for a permit to construct and operate a 79.2 kilometre (km) long 320 kilovolt (kV) power line from just north of Sherbrooke, Quebec to the New Hampshire border (the "Project"). The Project as applied for would increase HQT's capacity to export power into the New England grid. The estimated incremental transfer capacity with the Project in service would be:

(a) 1,128 MW in export mode (from Quebec to New England); and

(b) 1,075 MW in import mode (New England to Quebec).

On 28 February 2017, HQT applied to the Board to vary its EC-III-021 Certificate (the "Certificate"), modifying the definition of the authorized facility as described in Condition 2 of that Certificate. The proposed modification included the reconfiguration of the power lines that exit the Des Cantons substation including the re-use of a 4.2 km section of the 450 kV Nicolet-Des Cantons International Power Line ("IPL"), so that the 4.2 km segment can be operated at 320 kV (the "Variance Application").

HQT confirmed that the Variance Application was contingent on the issuance of the permit for the Permit Project. The NEB on its own motion assessed the Permit Project and Variance Application concurrently.

The NEB approved the Permit Project and issued the electricity permit EP-303 ("Permit"). The NEB also granted the Variance Application.

<u>Engineering Matters</u>

The NEB found that:

(a) the overall design of the proposed 320 kV Project used sound engineering practices in respect of structural design, layout, line and structure numbering, equipment selection, transfer capacity and reliability; and

(b) the construction, operation, and maintenance of the Project would meet all standards and requirements related to safety, reliability, and engineering.

Economic Feasibility and Need for the Project

The Board found that:

(a) the Project was responding to market need and that it would increase the export capacity of Quebec;

(b) the evidence provided by HQT regarding the market conditions was sufficient to demonstrate demand for the Project;

(c) HQT had sufficient financial resources in place to finance the construction and operation of the Project; and

(d) HQT had sufficient financial strength to finance the future abandonment of the Project, and the NEB approved HQT's abandonment cost estimate of $11.3 million for the Project.

Public Consultation

The NEB found that:

(a) HQT's consultation program and public consultation efforts were appropriate for the scope and scale of the Project;

(b) HQT had adequately identified and engaged stakeholders, developed engagement materials, notified stakeholders of the Project and responded to their input; and

(c) the public concerns received through the comment period had been addressed and mitigated by HQT.

Routing

The NEB found that the route selection and the criteria used to determine the route were acceptable and appropriate given the scope and scale of the Project.

In this respect, the NEB noted that following:

(a) HQT's efforts to determine an appropriate route, taking into consideration public input and land use in the area;

(b) HQT's route selection criteria, which considered:

(i) stakeholder concerns and minimized potential environmental and social impacts;

(ii) avoiding sensitive environmental areas; and

(iii) following existing infrastructure as much as possible, such that over 80% of the route follows the existing right-of-way; and

(c) the Project would be located entirely on private land.

Environment and Socio-Economic Matters

The NEB found that the carrying out of the Project was not likely to cause significant environmental and socio-economic effects, given the nature and scope of the Project, mitigation measures proposed by HQT, and the implementation of the Government of Quebec and NEB's mitigative conditions.

HQT conducted an environmental and socio-economic assessment for the Project (the "Environmental Assessment"). The Environmental Assessment assessed alternatives, including different routes, means and construction methods.

HQT applied for a certificate with the Province of Quebec where interested and affected parties were able to express their concerns under the provincial process. The NEB noted the responsibility of the Government of Quebec to oversee the Project as part of the province's issuance of the certificate under provincial jurisdiction. The Province of Quebec imposed conditions on its approval of the Project to protect the environment. These conditions included mitigation and/or compensation measures regarding the Forêt Hereford, wetlands, watercourses as well as certain wildlife and vegetation.

The NEB was responsible for issuing a federal permit and imposed several conditions to allow the NEB to verify that HQT fully implemented its environment protection commitments, including:

(a) Condition 10 requiring HQT to file an updated Environmental Protection Plan before commencing construction;

(b) Condition 17 requiring HQT to file post-construction monitoring reports to verify that any possible environmental issues that may arise were identified and mitigated accordingly; and

(c) Condition 13 requiring HQT to confirm that it has obtained all required archaeological and heritage resources clearances and authorizations from the province.

Aboriginal Matters

Concerning the design and implementation of HQT's Aboriginal consultation activities, the NEB held that HQT's design of Project-specific consultation activities was adequate given the scope and scale of the Permit Project.

The NEB further found that:

(a) the potential adverse effects of the Project on the current use of lands and resources for traditional purposes by Aboriginal groups were not likely to be significant;

(b) in light of the nature of the interests and the anticipated effects, there had been adequate consultation and accommodation for the purpose of the NEB's decision on the Project; and

(c) any potential Project-related impacts on the interests, including rights, of affected Aboriginal groups were not likely to be significant and could be effectively addressed.

The Project's study area was not within any territory subject to any Aboriginal land claims. The closest Aboriginal groups to the Project, the Odanak First Nation, and Wôlinak First Nation, were located over 80 km from the study area.

In addition to providing technical information addressing impacts of the Project on, among other things, wildlife, vegetation, and heritage resources, HQT was required to make all reasonable efforts to consult with potentially affected Aboriginal groups and to provide information about those consultations to the NEB. The NEB required including evidence on the nature of the interests potentially affected, the concerns that were raised and the manner and degree to which those concerns had been addressed.

The NEB explained that it evaluates the sufficiency of the applicant's consultation process and that HQT was expected to report on all Aboriginal concerns that were expressed to it, even if it was unable or unwilling to address those concerns.

Concerning the scope and depth of consultation, the NEB stated that it expects an applicant:

(a) to design and implement its consultation activities about the nature and magnitude of a project's potential impacts both from early in the design phase and into the future operational phase of a project;

(b) where there is a greater risk of more serious impacts on Aboriginal interests including rights, the NEB has higher expectations regarding the applicant's consultation with potentially impacted Aboriginal groups; and

(c) in contrast, where there is a remote possibility of an impact on Aboriginal interests, or the impacts are minor, the applicant's consultation will generally not be expected to be as extensive.

The NEB noted HQT's commitment to ongoing consultation with Aboriginal groups and its ongoing dialogue with Le Bureau du Ndakinna du Grand Conseil de la Nation Waban-Aki. The NEB also noted that the Permit Project was located primarily on privately owned land with limited access by Aboriginal groups.

Decision

For the reasons summarized above, the NEB found that further inquiry into HQT's application was not warranted. Accordingly, the Board did not recommend to the Minister that the Governor in Council designate HQT's application for a certificating procedure.

The NEB, therefore, issued the interconnection permit and Variance Order.

Maritime & Northeast Pipeline Management Ltd. – Application for Approval of 2017-2019 Toll Settlement – RHW-003-2017 Reasons for Decision
Tolls – Negotiated Settlement Agreement

In this decision, the NEB considered Maritime & Northeast Pipeline Management Ltd.'s ("M&NP") application (the "Application") for approval of its 2017-2019 Toll Settlement (the "Settlement") for final tolls over the period 1 January 2017 through 30 November 2019 (the "Settlement Period").

The NEB found that:

(a) the Settlement toll methodology was appropriate and resulted in just and reasonable tolls over the Settlement Period; and

(b) the Settlement struck a fair balance between the pipeline and its current shippers and the interests of future users of the system.

The NEB determined that the impact of the expected drop in billing determinants at the end of the Settlement Period should be addressed by the parties, during the Settlement Period.

Settlement Application

M&NP filed its Application under Part IV of the *National Energy Board Act* (the "*NEB Act*"), and the *National Energy Board Guidelines for Negotiated Settlements of Traffic, Tolls and Tariffs* (the "Guidelines"). M&NP indicated that the Settlement resulted from negotiations with the M&NP Tolls and Tariff Working Group ("TTWG"), comprised of representatives of M&NP and other parties interested in M&NP's tolls and tariff matters. The outcome of the TTWG vote was opposed with the majority of votes in favour of the resolution.

Figure: Map of M&NP System

<u>Settlement's Compliance with the Guidelines</u>

The NEB explained that it considers negotiated settlements as an opportunity for interested parties to resolve issues without resorting to a hearing process.

The Guidelines set out that:

- a settlement must not fetter the Board's ability and discretion to take into account any public interest considerations which may extend beyond the immediate concerns of the negotiating parties;
- the settlement process must produce adequate information on the public record for the Board to understand the basis for the agreement, assess its reasonableness, and to be able to determine that the resulting tolls are just and reasonable and not unjustly discriminatory; and
- for contested settlements, the applicant must make submissions as to why the Board should accept the settlement.

The NEB noted that there was broad support for the Settlement from both the firm service shippers and shippers in the secondary market.

Heritage Gas Limited ("Heritage"), and its affiliates AltaGas Ltd. and Alton Natural Gas Storage requested that the NEB decline to approve the Application and, instead, initiate a proceeding to determine the tolling methodology and tolls that would be appropriate for M&NP given its high level of underutilization. The Settlement was approved notwithstanding this opposition. Heritage opposed the Settlement and raised concerns regarding underutilization, whether the pipeline was used and useful, toll stability and certainty for the market beyond the Settlement Period.

<u>Depreciation and Terms of the Settlement</u>

The NEB found that the accelerated depreciation and the reduced return on equity for M&NP contained in the Settlement were consistent with the principle of intergenerational equity and sufficiently responsive to the realities facing M&NP.

The Board found that:

(a) the Settlement Period was appropriate to the conditions and market realities facing M&NP; and

(b) the Settlement proactively took steps during the Settlement Period to address the ongoing concerns of the enduring market after the expiry of the Backstop Agreement and the Settlement Period.

The Board noted Heritage's concerns that M&NP had not consulted with the TTWG about M&NP's assumptions regarding post-Settlement tolling initiatives. To provide shippers with a measure of toll certainty and the ability to appropriately plan their business activities and transportation requirements, the NEB encouraged meaningful consultation and discussions between M&NP and its shippers, well in advance of the expiration of the Settlement.

<u>Abandonment Funding</u>

M&NP stated that the Settlement spanned an important period in the evolution of the M&NP system and effectively provided a bridge from the pre-2020 period, in which supply-driven dynamics predominated, to 2020 and beyond when the system would transition to largely domestic market-driven dynamics.

The Board noted that in the MH-001-2013 decision, it found:

(a) if there was a change in circumstances between Board-mandated reviews that materially affect the amount required to be collected, then the company must revise their annual contribution amount, rather than waiting for the NEB's next review;

(b) if there was a significant risk that adequate funds would not be set aside, the NEB may, on its own initiative, require further coverage of any unfunded future costs through a secondary mechanism;

(c) there was a considerable risk for M&NP to under-collect the cost of abandoning its system because the current supply available to the M&NP system was limited;

(d) a 19.5-year collection period better aligned with current forecasts of the supply available to the M&NP system; and

(e) M&NP could apply to the Board to vary its collection period if significant supply developments were to occur.

In this case, the NEB considered M&NP's current situation might constitute a "significant supply development". If nothing else, it likely represented a material change in circumstances between NEB mandated reviews of the collection period. Due to the production declines and anticipated change in use of the system, the NEB found that the 19.5 year collection period originally set out in MH-001-2013 should be revisited.

The NEB considered that M&NP's abandonment cost toll surcharge should be increased during the Settlement Period. In the NEB's view, such an approach could reduce the risk of underfunding in the future, and more appropriately align with the principle of intergenerational equity. Abandonment funding was however outside of the scope of this Settlement, and the NEB had not solicited extensive evidence on the matter. Therefore, the NEB determined that it was premature to decide whether modifying the collection period and/or increasing the surcharge over the Settlement Period was warranted.

Given the expected reduction in billing determinants following the Settlement, the NEB found that the determination of appropriate abandonment contribution amounts was time sensitive. Accordingly, the NEB directed M&NP to file an application, by 1 May 2018, proposing an updated collection period and annual collection amount for the Settlement Period and beyond. The NEB directed that the application address, at a minimum:

(a) whether the collection period remains appropriate, or whether it should be truncated/lengthened;

(b) whether it may be appropriate to have differing associated contribution amounts during and after the Settlement, based on the expected change in use of the system;

(c) whether the amount set aside by M&NP should be accelerated over the Settlement Period;

(d) whether the abandonment surcharge should be increased over the Settlement Period;

(e) markets and supply, during both the Settlement and post-Settlement Periods, including supporting evidence using currently available estimates for the post-2019 period;

(f) the appropriateness of M&NP's abandonment trust's investment policy as set out in its Statement of Investment Policies and Procedures filed with the Board, during both the Settlement and post-Settlement Period; and

(g) how the proposed collection period and contribution amounts respect the principle of intergenerational equity.

<u>Disposition</u>

The NEB approved the Application as applied for by M&NP, subject to the conditions in the accompanying toll order.