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REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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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.

IN THIS ISSUE:

Alberta Energy Regulator 2

Syncrude Canada Limited - Application for Aurora North Tailings Management Plan (AER Decision 20180613A) 2

Canadian Natural Resources Limited - Application for a Single-Well Bitumen Battery - Waseca Formation (AER Decision 2018 ABAER 004) 6

Prosper Petroleum Limited - Rigel Project (AER Decision 2018 ABAER 005) 9

Alberta Utilities Commission 15

Sale and Transfer of the Municipality of Crowsnest Pass Electric Distribution Assets to FortisAlberta Inc. (Decision 21785-D01-2018) 15

ATCO Gas, a Division of ATCO Gas and Pipelines Ltd. - Z Factor Application for Recovery of 2016 Regional Municipality of Wood Buffalo Wildfire Costs (Decision 21608-D01-2018) 16

Direct Energy Regulated Services - 2017-2018 Default Rate Tariff and Regulated Rate Tariff (Decision 22004-D01-2018) 21

National Energy Board 26

NOVA Gas Transmission Ltd. Application for Approval of 2018-2019 Revenue Requirement Settlement and Final 2018 Rates, Tolls, Charges and Abandonment (Letter Decision and Order TG-004-2018) 26

ALBERTA ENERGY REGULATOR

Syncrude Canada Limited - Application for Aurora North Tailings Management Plan (AER Decision 20180613A)
Tailings Management Plan - Water-capping Technology

Background

Syncrude Canada Limited's ("Syncrude") Aurora North oil sands processing plant and mine ("Aurora North") received approval through a joint Alberta Energy and Utilities Board ("EUB") and Government of Canada panel in 1997. Syncrude commenced production at Aurora North in 2001, and tailings treatment in 2013 using composite tailings ("CT") technology.

Application

In this decision, the AER considered Syncrude's application pursuant to section 13 of the *Oil Sands Conservation Act* ("*OSCA*") for approval of its tailings management plan ("TMP") for Aurora North.

The application sought approval for Syncrude's TMP from the present until 2050.

For the reasons summarized below, the AER approved Syncrude's application, subject to terms and conditions (the "Approval Conditions").

The Approval Conditions imposed by the AER addressed:

- stakeholder and indigenous community engagement;
- project-specific thresholds for both new and legacy fluid tailings;
- tailings treatment technology and deposit plans and updates, including mitigation measures and research, monitoring, evaluation, and reporting; and
- environmental effects and implications.

Aurora North's TMP Approval and Conditions

The AER had concerns about the ability of Syncrude's applied-for TMP to meet the *Lower Athabasca Region: Tailings Management Framework for Mineable Athabasca Oil Sands*' ("*TMF*") objectives, given the TMP being dependent on water-capping, a technology subject to further assessment, research, and future policy. In the AER's view, its approval together with the Approval Conditions reflected *TMF* outcomes and set conditions that ensured appropriate information was captured in a timely manner to manage risk and make appropriate regulatory decisions at Aurora North.

Regulatory Scheme

The Government of Alberta regulates tailings under the *TMF*.

Tailings are a by-product of the process used to extract bitumen from mined oil sands and consist of water, silt, sand, clay and residual bitumen.

The AER regulates tailings from oil sands mining operations to ensure that the tailings are managed in an efficient, safe, orderly and environmentally responsible manner over their entire life cycle.

The AER applies a risk-based approach to regulating, where higher-risk activities receive the greatest regulatory oversight. Given the nature and scale of fluid tailings generated by oil sands mine operations and the ongoing research and development of tailings treatment technology, fluid tailings management is one of Alberta's higher-risk industrial activities.

The AER noted the following regarding the *TMF*:

- The *TMF*'s objective is to minimize fluid tailings accumulation by ensuring that fluid tailings are treated and reclaimed progressively during the life of a project, and all fluid tailings associated with a project are ready-to-reclaim ("RTR") within ten years of the end of mine life.
- The *TMF* establishes four outcomes: land use must be returned to Albertans, sustainable ecosystem, liability is minimized to Albertans, and environmental effects are managed.
- As part of the implementation of the *TMF*, the AER released Directive 085: *Fluid Tailings Management for Oil Sands Mining Projects* ("*Directive 085*"), which sets out requirements for all fluid TMPs, including both existing fluid tailings (i.e., legacy) and new fluid tailings.

Tailings Treatment Technology

Composite Tailings Technology

The AER authorized Syncrude to continue to use CT technology to treat fluid tailings. However, the AER found that CT technology treatment capacity at Aurora North was constrained by coarse sand availability due to competing construction and reclamation needs.

To meet long-term reclamation outcomes, the AER required Syncrude to provide the following information as part of its *Environmental Protection and Enhancement Act*

(“*EPEA*”) life of mine closure plan and mine reclamation plan:

- capping material types, objectives, and implications;
- material balances for coarse sand and any other suitable capping materials;
- contingency plans for capping material shortages; and
- an assessment of the minimum sand cap thicknesses required to manage the groundwater table, manage tailings pore water flux, provide adequate tailings deposit strength and trafficability, and drainage.

The AER also required Syncrude:

(a) to provide in its annual reclamation progress tracking report the volume of coarse sand and suitable overburden available as capping material for the CT placement locations; and

(b) to submit a capping research plan by December 31, 2018, for its CT deposits.

Water-capping technology

Directive 085 requires that where water-capped fluid tailings technology is used to generate the inventory forecast in the profiles, an alternative tailings treatment technology must also be provided, including timeframes for implementation.

The AER prohibited Syncrude from placing any water, including industrial wastewater, above treated or untreated fluid tailings to create a water-capped pit lake, based on the following:

- Water-capping technology was subject to further assessment, research, and future policy and extensive research on water-capped tailings were continuing.
- If the feasibility of water-capped pit lakes was demonstrated and the Government of Alberta implemented policies permitting their use, Syncrude must apply to the AER to amend their approval.
- Syncrude may continue to plan on the basis that water-capped pit lakes are an option unless water-capped tailings technology proves not to be feasible and/or Government of Alberta policy does not allow it.

The AER has required Syncrude to plan for an alternative to water-capped pit lakes. Syncrude is required to describe, by December 31, 2018, how it will develop feasible alternative tailings treatment technologies and an implementation plan to treat the volume of fluid tailings that is proposed to be treated with water-capping technology. Should Syncrude continue to propose the use of water-capping technology, Syncrude must provide feasible alternative tailings treatment technologies and an implementation plan in the updated 2023 TMP.

<u>Fluid Tailings Profiles and Project-Specific Thresholds</u>

Based on Syncrude’s application, its legacy fluid tailings and new fluid tailings profiles indicated that all legacy fluid tailings would achieve RTR status by end of mine life (2040) and all new fluid tailings would achieve RTR in 2045, five years after end of mine life.

Although the AER found that Syncrude’s profiles met the *TMF*’s objective, the AER had a number of concerns with the profiles. The AER was concerned about the ability of Syncrude’s profiles to meet the *TMF* objective given the TMP depending on the use of water-capping technology.

The AER required that Syncrude submit by December 31, 2018, how it will develop alternative tailings treatment technologies and an implementation plan to treat the volume of fluid tailings that Syncrude proposed to treat with water-capping technology.

Given that water-capped pit lakes are prohibited, and water-capping technology is subject to further assessment, research, and future policy, the AER ordered Syncrude to provide, by December 31, 2023, a TMP that included updated legacy fluid tailings and new fluid tailings profiles.

Legacy Fluid Tailings Profile

Legacy fluid tailings are fluid tailings that existed before January 1, 2015. All legacy fluid tailings must be RTR by end of mine life.

The AER found that Syncrude’s legacy fluid tailings profile met the *TMF*’s objective because the existing volume of 108 Mm3 would be treated and would achieve RTR status by 2040, end of mine life. However, the AER was concerned about the ability of Syncrude’s legacy profile to meet the *TMF*’s objective, based on Syncrude’s reliance on water-capping technology.

The AER required Syncrude to submit an updated TMP by December 31, 2023, that includes an updated legacy fluid tailings profile.

New Fluid Tailings Profile

The *TMF* defines new fluid tailings as fluid tailings that are produced after January 1, 2015. All new fluid tailings must be RTR within ten years of end of mine life.

The AER found that Syncrude's new fluid tailings profile would meet the *TMF*'s objective as all new fluid tailings were expected to achieve RTR status in 2045, five years after the end of mine life.

Syncrude was depending on using water-capping technology to achieve the *TMF*'s objective. In this regard, the AER had several concerns:

- It was unclear whether Syncrude's new fluid tailings profile excluded fluid tailings volumes generated from froth transferred to the Mildred Lake mine from Aurora North.
- Although the *TMF* acknowledged that it might take more than three to ten years to accumulate the peak volume, Syncrude was proposing growth in tailings accumulation until reaching its peak accumulated volume in 2040.
- Syncrude had not demonstrated that the fluid tailings treatment capacity was equal to or greater than the new fluid tailings production rate as required by the *TMF* and Directive 085.

The AER required Syncrude to submit an updated 2023 TMP that includes an updated new fluid tailings profile. The updated profile must demonstrate the *TMF's* objective is achieved and ensure treatment capacity is equal to or greater than the new fluid tailings production rate by December 31, 2027. The profile must also include the timing when RTR status is achieved and reflect all available information on water-capping technology.

<u>Thresholds</u>

With respect to thresholds, the AER explained that:

- The volume of accumulated fluid tailings is the primary indicator in the TMF used to manage and decrease liability and environmental risk resulting from the accumulation of fluid tailings.
- Triggers and a limit ("thresholds") are set relative to the fluid tailings profiles.
- The thresholds are intended to ensure that fluid tailings are not accumulating beyond a volume or at a rate that precludes operators from meeting the *TMF*'s objective.

The three thresholds under the *TMF* are the profile deviation trigger, the total volume trigger, and the total volume limit:

(a) Profile deviation trigger:

(i) applies to both legacy fluid tailings and new fluid tailings profiles;

(ii) occurs when the volume of fluid tailings is growing 20 percent faster than that approved for the profile;

(iii) is based on when the fluid tailings volume growth is 20 percent higher than that in the approved profile; and

(iv) allows a five-year rolling average to account for year-over-year variability.

(b) Total volume trigger:

(i) applies to the new fluid tailings profile;

(ii) occurs when the volume of fluid tailings has exceeded its approved maximum accumulation and requires additional management action; and

(iii) is based on a level equal to 100 percent of the greater of the maximum approved fluid tailings volume profile or the end of mine life target.

(c) Total volume limit:

(i) under the *TMF* is the volume of fluid tailings above which it presents an unacceptable risk to the environment and potential long-term liability;

(ii) if exceeded will compromise the ability of an operator to have all of their fluid tailings in an acceptable management state (i.e., RTR) within ten years of the end of mine life. Therefore, the most severe management responses are initiated;

(iii) is based on 140 percent of the greater of the maximum approved fluid tailings volume profile or the end of mine life target; and

(iv) applies to the new fluid tailings profile.

To allow for year-over-year variability, the AER set the profile deviation trigger for Syncrude as a five-year rolling average of the annual profile deviation. The profile deviation trigger applied to both the legacy fluid tailings and new fluid tailings profiles.

The AER set the thresholds in accordance with the *TMF* and *Directive 085*, and therefore Syncrude was subject to a total volume limit and total volume trigger, in addition to the profile deviation trigger.

The AER recognized that the maximum approved fluid tailings volume was 130 Mm3. However, this peak volume only occurred in a single year, near the end of mine life. The AER determined that it would be inappropriate to set a total volume trigger and limit based on this one-time peak volume due to the inflated threshold it would create for the entirety of the profile. As per Directive 085, the AER will consider all the circumstances when considering appropriate management responses where a threshold is exceeded.

The AER set the total volume trigger at 113 Mm3 and the total volume limit at 158 Mm3.

Storage

With respect to storage of tailings deposits, the AER required Syncrude to report annually on the available storage capacity of each tailings deposit or pond that contains water or tailings and to estimate the storage volume requirements for the next five years.

Ready-to-Reclaim Criteria

Under the TMF and Directive 085, fluid tailings are considered RTR when they have been processed with an accepted technology, placed in their final landscape position, and meet RTR criteria.

RTR criteria are used to track the performance of a tailings deposit toward its ability to be reclaimed as predicted.

RTR criteria are intended to support the objective of reclaiming oil sands mining projects to self-sustaining locally common boreal forest ecosystems that are integrated with the surrounding area and consistent with the values and objectives identified in local, sub-regional and regional plans.

Two sub-objectives address different aspects of performance:

- Sub-objective 1: The deposit's physical properties are on a trajectory to support future stages of activity.

- Sub-objective 2: To minimize the effect the deposit has on the surrounding environment and ensure that it will not compromise the ability to reclaim to a locally common, diverse and self-sustaining ecosystem.

The TMF and Directive 085 allow operators to develop RTR criteria that are suitable for their type of tailings, technology, deposit and future reclamation activities.

Under Directive 085, treated tailings that meet their applicable RTR criteria can be removed from the fluid tailings inventory because they are on a trajectory to meet long-term reclamation outcomes. In circumstances where RTR criteria are no longer met, or there is a deviation from the expected trajectory, Syncrude must identify the volume not meeting the RTR criteria and the degree of nonperformance.

Measurement and Averaging

Each treated tailings deposit must be measured to determine if the RTR criteria have been achieved. Directive 085 requires operators to submit a measurement system plan six months from the date of an approved TMP.

Syncrude was required to develop a measurement system plan that included the following:

- definitions of parameters for fluid tailings and RTR criteria measurements;

- reference to standards and procedures used to measure fluid tailings and treated tailings and RTR criteria;

- an explanation of and justification for measurement procedures that are unique to Syncrude and its plan;

- evidence that the plan will address the measurement outcomes as per section 5 of Directive 085;

- an explanation of how each of the deposit's RTR criteria will be measured using deposit sampling, calculated, and reported;

- a description of the tailings deposit sampling, measurement, and survey program; and

- justification of how measurement, sampling, and spacing intervals will:

    - show the variation of the tailings deposit properties;

    - verify that the tailings deposit is achieving RTR criteria; and

    - identify any material in the tailings deposit that is not achieving RTR criteria.

The AER found that Syncrude's proposed averaging process would obscure a meaningful understanding of the deposit volumes that have been treated unsuccessfully or were failing to improve as expected. The AER noted that a deposit might show excellent performance on average while a significant portion of the tailings deposit is underperforming and compromising the ability to reclaim.

The AER, therefore, required Syncrude to measure the volume of treated tailings based on deposit sampling. The deposit sampling must be sufficient to identify variability within the entire deposit.

Sub-objective 1: Solids Content

Syncrude proposed to use the solids content by weight of a deposit as a sub-objective 1 RTR criterion.

The AER found that solids content alone may not be sufficient to measure a deposit's performance or its ability to meet future stages of reclamation activity and meet the objectives of the TMF.

The AER, therefore, required Syncrude, for each treated tailings deposit, to monitor and report annually, sands-to-fine ratio, effective stress, deposit consolidation, pore water pressure, clay types and percentage, and any other parameters considered relevant by the AER or Syncrude.

The AER determined that, given the additional monitoring and reporting required, the use of the solids content by weight of a deposit was an acceptable sub-objective 1 RTR criteria measure.

Sub-objective 2

Syncrude proposed sub-objective 2 RTR criteria related to monitoring:

- treated fluid tailings and fluid levels compared to design elevations;
- slope movement and pore pressure; and
- observation wells for occurrences of elevated chloride concentrations.

The AER did not approve Syncrude's proposal of monitoring treated fluid tailings and fluid levels compared to design elevations, slope movement, and pore pressure as Syncrude did not provide sufficient supporting information.

<u>Stakeholder and Indigenous Community Engagement</u>

The *TMF* and *Directive 085* describe the importance of transparency, engagement, and enhancing stakeholder and indigenous community understanding of fluid tailings management.

To ensure continued transparency, information sharing and involvement in tailings management, the AER required Syncrude to engage stakeholders and indigenous communities on tailings management activities undertaken pursuant to the approval.

The AER also required Syncrude to:

(a) hold an annual forum with stakeholders and indigenous communities regarding tailings management activities; and

(b) report to the AER annually on its engagement efforts.

<u>Summary</u>

The AER approved Syncrude's TMP for Aurora North, subject to conditions.

Canadian Natural Resources Limited - Application for a Single-Well Bitumen Battery - Waseca Formation (AER Decision 2018 ABAER 004)
Facility Application – Bitumen Battery

<u>Introduction</u>

In this decision, the AER considered Canadian Natural Resources Limited's ("CNRL") application for approval to construct and operate a single-well battery to produce and store bitumen containing no hydrogen sulphide ("H2S") at an existing well site about seven kilometres ("km") west of Canadian Forces Base Cold Lake (the "Application"). CNRL made the Application under section 7.001 of the *Oil and Gas Conservation Rules* ("*OGCR*") and section 5.5(12) of AER Directive 056: *Energy Development Applications and Schedules* ("Directive 056").

The AER approved the Application subject to the conditions.

<u>The Application</u>

In the Application, CNRL proposed:

(a) to re-complete an existing gas well at the site, which had been shut-in since December 2016, to produce bitumen; and

(b) to construct a battery, consisting of a wellhead, storage tank, and compressor, to store bitumen containing no H2S (that is, less than 0.01 moles per kilomole) (the "Battery").

CNRL also requested:

(a) a variance to the AER's surface spacing requirements, since part of the Battery was proposed to be located less than 60 metres from an existing pipeline owned by Husky; and

(b) a licence with a two-year term to begin project activities, instead of the standard one-year term, to allow CNRL to consider market conditions and related factors before starting construction.

Framework for the Decision

The AER set out the following legal framework for its decision on the Application:

- Under section 2(1) of the *Responsible Energy Development Act* ("*REDA*"), the AER's mandate is to provide for the efficient, safe, orderly, and environmentally responsible development of energy resources in Alberta and to regulate, in respect of energy resource activities, the protection of the environment.

- The AER's decision must be consistent with the purposes set out in sections 4(b), (c), and (f) of the *Oil and Gas Conservation Act* ("*OGCA*"), including providing for the following:

    - safe and efficient practices in the locating, spacing, drilling, operating, and abandonment of wells and facilities and in operations for the production of oil and gas or the storage or disposal of substances [s 4(b)];

    - economic, orderly and efficient development in the public interest of the oil and gas resources of Alberta [s 4(c)]; and

    - pollution control [s 4(f)].

- Under section 15 of *REDA* and section 3 of the *REDA General Regulation*, the AER had to consider:

    - social and economic effects of the proposed Battery;

    - effects of the proposed Battery on the environment; and

    - impacts on landowners from use of the land for the proposed Battery.

List of Issues

The AER considered the following issues:

- participant involvement program;

- infrastructure spacing requirements;

- project need and location;

- potential impacts on the leaning tree;

- potential impacts of air emissions, dust, and odours on human health;

- noise;

- traffic and safety concerns;

- future subdivisions, land use, and land sales;

- emergency response; and

- potential impacts on water wells, groundwater, or aquifers.

Participant Involvement Program

Under the *OGCR* and *Directive 056*, a single-well facility producing resources containing no H2S does not require a licence if there are no outstanding concerns about the development. Because CNRL was unable to resolve the concerns of all potentially affected landowners, it was required to file a nonroutine application with the AER.

The AER found that CNRL's participant involvement program satisfied the requirements of *Directive 056* and that CNRL was responsive to requests to expand the program.

Infrastructure Spacing Requirements

Section 8.030(4) of the *OGCR* requires that a tank containing fluids other than fresh water be located at least 60 metres ("m") from surface improvements, subject to a lesser distance permitted by the AER.

The dike for the bitumen storage tank was proposed to be located 20 m from Husky's existing pipeline. Since the pipeline was considered a surface improvement under the *OGCA*, CNRL requested a variance to permit the tank to be located less than 60 m from the pipeline.

The AER granted the spacing relaxation request based on the follow:

(a) CNRL's request could be accommodated within the current lease area;

(b) granting the spacing relaxation request would not create any safety concerns;

(c) Husky consented to CNRL constructing the facility 20 m from its pipeline; and

(d) no other surface improvements were located within 60 m of the tank.

Project Need and Location

The AER found that:

(a) there was a need for the project; and

(b) the project, if successful, would have economic benefits and was consistent with the safe, orderly, efficient, and environmentally responsible development of Alberta's energy resources.

The AER supported these findings based on the following:

(a) no party submitted evidence to demonstrate that any alternative location for the project would be better than the proposed location;

(b) CNRL owned the mineral rights in the area, and the proposed project would allow CNRL to test the Waseca Formation and potentially extract bitumen efficiently;

(c) the project would minimize potential environmental and landowner impacts by using an existing lease and well; and

(d) the potential revenue for CNRL and fiscal benefits to governments and the local economy represented positive economic impacts of the project.

Potential Impacts on the Leaning Tree

The AER went on to consider landowners' concerns that CNRL's activities could negatively affect the "leaning tree," a jackpine estimated to be about 100 years old, located on the lease site.

The AER noted that:

(a) the leaning tree had been gradually leaning closer to the ground for many years; and

(b) it had appeared in a book of heritage trees of Alberta due to its age and distinctive appearance.

The AER found that by implementing the mitigation measures imposed as a condition by the AER, CNRL would take reasonable steps to mitigate potential impacts on the leaning tree.

To reduce risks to the leaning tree, the AER required CNRL to implement the following mitigation:

(a) observe a minimum 13 m buffer between the tree and construction and operation activities;

(b) before construction, hire a professional arborist to assess whether the leaning tree is still alive and share the arborist's findings with the landowners; and

(c) if the leaning tree was still alive when construction began, install a liner and clay over the grass and topsoil to limit ground vibrations and minimize disturbances to the tree.

Potential Impacts of Air Emissions, Dust, and Odours on Human Health

The AER found that the project would have minimal effects on air quality and was not likely to cause adverse health impacts under normal operating conditions, based on the following:

(a) air emissions would be relatively limited from this type of project (single-well, single storage tank, two small engines, tank heater);

(b) the project emissions would not result in exceedances of Alberta's ambient air quality objectives, which are intended to protect the environment and human health;

(c) the project was not expected to release H2S, which can contribute to odours; and

(d) the 50 km/hr speed limit on the access road would limit dust.

Noise

AER Directive 038: *Noise Control* ("Directive 038") sets limits for noise levels during energy project operations.

In this case, the AER found that:

(a) modelling conducted for CNRL's Noise Impact Assessment (the "NIA") satisfied the requirements of Directive 038;

(b) the NIA predicted that daytime and nighttime sound levels at all nearby existing and planned residences would be at or below permissible sound levels during project operations, and meet the requirements in Directive 038 (before mitigation); and

(c) the additional mitigation measures recommended in the NIA would further reduce the potential for noise impacts.

Traffic and Safety Concerns

With respect to landowners' concerns regarding traffic and road safety impacts, the AER explained that it does not have jurisdiction over highway traffic or safety matters. The AER's jurisdiction is limited to the clean up of spills of oil, water, or unrefined products that occur during transportation associated with the project, the location of the access road, and conditions relating to its construction and operation.

Based on Alberta Transportation's approval of the sight lines in both directions from the well site's access road and CNRL's requirement for its drivers to respect the speed limits and drive courteously, the AER did not expect any safety concerns related to the marginal increase in traffic at the well site.

Future Subdivisions, Land Use, and Land Sales

The AER was not persuaded by landowners' submission and evidence that the project would reduce their property values or adversely affect their future land use plans.

The AER found that:

(a) the Battery would not be visible from current residences or planned retirement homes; and

(b) the Battery might be visible from one or more of the landowners' proposed subdivided lots, but the distance and the trees between the project and the lots would reduce the visual impact.

The AER further noted that oil and gas facilities were a common sight in the area and that there were no specific regulatory requirements related to visual impacts of energy projects.

Emergency Response

The AER found that CNRL's plan for emergency response was reasonable and met all AER requirements, based on the following:

(a) there was an exceedingly small chance of a high-impact emergency situation requiring evacuation of nearby residents for this type of facility;

(b) CNRL's corporate Emergency Response Plan ("ERP") satisfied the requirements of Directive 071, namely:

(i) average emergency response time of two hours or less was reasonable;

(ii) the containment ring around the storage tank would capture any large spills from a tank failure; and

(iii) operators would be able to contain any small spills on the lease site by immediately implementing the ERP.

Potential Impacts on Water Wells, Groundwater, and Aquifers

The AER found that with the condition set out below, the project was unlikely to negatively affect groundwater, water wells, aquifers, or surface water bodies, such as the Beaver River.

The AER imposed as a condition a requirement that CNRL pressure test the well casing at the level set out in Directive 013 for medium-risk wells before re-completion activities begin.

Conclusion

The AER concluded that the project met or exceeded all applicable AER regulatory requirements, could be constructed and operated safely, and was consistent with the efficient, safe, orderly, and environmentally responsible development of Alberta's energy resources.

The AER therefore approved:

(a) CNRL's single-well bitumen battery, with conditions; and

(b) CNRL's request for a two-year licence and spacing variance.

Prosper Petroleum Limited - Rigel Project (AER Decision 2018 ABAER 005)
Bitumen Recovery Scheme – Oil Sands Conservation Act – Environmental Protection and Enhancement Act Application – Water Act – Aboriginal Impacts

In this decision, the AER approved Prosper Petroleum Limited's ("Prosper") *Oil Sands Conservation Act* ("*OSCA*") application to construct and operate a bitumen recovery scheme, including a central processing facility ("CPF") and supporting infrastructure (the "Rigel Project" or the "Project"). The AER also approved Prosper's *Environmental Protection and Enhancement Act* ("*EPEA*") application for the construction, operation, and reclamation of the Rigel Project. In addition, the AER approved Prosper's *Water Act* Application to withdraw 255,500 m3/year of nonsaline water from the Viking and Undifferentiated Drift formations. All of these approvals were subject to conditions.

Prosper's Rigel Project Application

Prosper applied to the AER for approval of the following:

- approval under the *OSCA* to construct and operate a bitumen recovery scheme (the "*OSCA* Application");
- approval under the *EPEA* for the construction, operation, and reclamation of the Project (the "*EPEA* Application"); and
- approval under the *Water Act* to withdraw 255,500 m3/year of nonsaline water from the Viking and Deep Drift formations (the "*Water Act* Application").

The Rigel Project would use steam-assisted gravity drainage ("SAGD") to produce a maximum of 1,600 m^3 of bitumen per day from the Wabiskaw formation.

The proposed Rigel Project components included a CPF for steam generation and production, connected to six multiwell pads. Each pad would have eight horizontal SAGD well pairs (injection and production). Additional proposed surface facilities included observation wells, water source wells, production facilities, water treatment and recycling facilities, pipelines, support buildings, an access road, utility corridors and rights of way, a laydown area, sumps, borrow pits, and a construction camp.

Framework for Decision

The AER set out the following framework for its decision on the application:

(a) The AER's decisions must be consistent with its mandate set out in section 2 of *REDA* to "provide for the efficient, safe, orderly, and environmentally responsible development of energy resources in Alberta";

(b) With respect to Aboriginal impacts:

(i) the AER must consider effects on treaty and Aboriginal rights when considering the *OSCA*, *EPEA*, and the *Water Act*;

(ii) however, as expressly stated in section 21 of *REDA,* the AER does not have jurisdiction to consider whether Crown consultation for Rigel Project was adequate; and

(iii) the Aboriginal Consultation Office ("ACO") deals with the adequacy of consultation and provides a report to the AER.

(c) Under section 10 of the of the *OSCA*, the AER:

(i) must find approval of the Project to be in the public interest;

(ii) may not issue an approval under section 10 of the *OSCA* without prior authorization from the lieutenant governor in council; and

(iii) because the *OSCA* is an energy resource enactment, section 15 of *REDA* and section 3 of the *REDA General Regulation* require the AER to consider the Rigel Project's social and economic effects, environmental effects, and effects on landowners.

(d) Under sections 66 and 137 of the *EPEA*, the AER must consider whether approval of the Rigel Project's CPF and associated infrastructure is consistent with the *EPEA* purpose of protecting the environment and promoting sustainable resource development while considering the need for Alberta's economic growth and prosperity;

(e) Section 20 of *REDA* requires the AER to act in accordance with the *Lower Athabasca Regional Plan* ("LARP") since Prosper's Rigel Project was located in the LARP area; and

(f) Under section 49 of the *Water Act*, the AER must decide whether approving the *Water Act* Application would be consistent with the conservation, management, and wise use of water resources in Alberta.

OSCA Application re Bitumen Recovery Scheme

Public Interest

For the reasons summarized below, the AER found the Rigel Project to be in the public interest. The AER explained that the public it considered was all Albertans. The AER concluded that benefits to Albertans outweighed the burdens.

In considering the public interest, the AER considered the following:

(a) safety and efficiency;

(b) impacts on existing rights of Aboriginal people;

(c) impacts on the environment (addressed in its consideration of the *EPEA*); and

(d) social and economic Impacts.

Safety and Efficiency

The AER found that Prosper would meet or exceed the relevant regulatory requirements and be able to operate the Rigel Project safely.

The AER found that Prosper's Emergency Response Plan ("ERP"), including spill response, adequately addressed the following:

- eliminating potential ignition sources;
- lessening the severity of a spill;
- notifying appropriate personnel, spill responders, and regulatory officials;
- identifying the type and extent of the spill;
- identifying the spilled material;
- identifying equipment, services, and assistance required;
- determining appropriate ways of containing and cleaning up the spill; and
- documenting all actions.

Efficiency

The AER was satisfied that Prosper's bitumen recovery scheme for the Rigel Project would be efficient because it was designed to maximize recovery of the oil sands resource, while minimizing adverse impacts.

Fort McKay Métis Community

The AER explained that the Supreme Court of Canada has said that the rights of Métis peoples that are protected under section 35 of the Constitution are those practices integral to the distinctive culture of the community at the time of effective European control of the relevant area.

For the purpose of this decision, the AER considered Fort McKay Métis to be a rights-bearing community with the rights to hunt and harvest on the lands and waters extending from Fort McKay west to Moose Lake and south to include the Prosper lease.

For the reasons summarized below, the AER determined that the possible limitation on the Fort McKay Métis community members' choice of where and when to exercise their Aboriginal rights was significant enough to weigh in the public interest balance, but not significant enough to tip the balance against the Rigel Project.

With respect to impacts on traditional fishing uses, the AER found that:

(a) the Fort McKay Métis community had used and currently uses lands on and near the Moose Lake reserves for hunting, trapping, and fishing;

(b) Moose Lake was an important year-round fishery for members of the community; and

(c) some members of the community might be afraid to eat fish from Moose Lake if more oil sands development occurred in the area.

However, the AER was not persuaded that Prosper's Rigel Project would likely result in harm to the fishery in Moose Lake.

With respect to its ability to pass on traditional knowledge, the AER found that:

(a) it was very important to the community to be able to continue to learn and pass on traditional knowledge and practices such as hunting, trapping, and fishing for food in the Moose Lake area;

(b) to continue to exercise their Aboriginal rights, Fort McKay Métis community members must be able to continue to pass on traditional knowledge; and

(c) industrial activity on the lands comprising the Prosper lease might cause members of the community to value/perceive the lands and the resources the lands support differently than they do now and that this was a negative social effect.

However, the AER was unable to conclude that approval of the Rigel Project would prevent Fort McKay Métis from continuing to exercise its Aboriginal rights in its traditional territory.

Social and Economic Impacts

Directive 023 sets out application requirements to allow the AER to assess the social and economic effects of proposed oil sands projects (e.g. population, housing, employment, economic activity, transportation, infrastructure and services, taxes, royalties, gross domestic product, labour income, capital costs, and annual operating expenditures).

With respect impacts on the demand for housing, traffic, and local infrastructure, the AER made the following findings:

(a) because camps would be used for construction, drilling, and operations, population effect on the region would not increase demand for housing in the region;

(b) the increase in overall traffic volume resulting from the Rigel Project would be minimal and that Prosper's commitments and proposed mitigation are acceptable; and

(c) any demand on local infrastructure and services that results from the Rigel Project would be within existing capacity.

With respect to economic benefits, the AER found that the economic benefits expected from the Rigel Project would be substantial for a project of its size, particularly regarding royalties to Alberta, taxes to all levels of government, and employment income.

Additional Public Interest Considerations

The AER found that, based on the above, the balance between the overall economic benefits, including employment, and the negative impacts of the Prosper Rigel Project were more or less even. To answer the question of whether the Rigel Project was in the public interest, the AER considered the following additional public interest factors:

(a) Fort McKay First Nation's argument that the AER should not frustrate the Moose Lake Adaptive Management Plan ("MLAMP") negotiations;

(b) Prosper's submissions about the desirability of regulatory and investment certainty; and

(c) Public policy guidance expressed through the *OSCA*, *EPEA*, the *Water Act* and *REDA*.

For the reasons summarized below, the AER determined that approval of the Rigel Project was in the public interest.

The AER found that the Fort McKay First Nation's assertion that the AER approval not frustrate MLAMP negotiations did not tip the public interest balance against approving the Rigel Project, based on the following:

(a) to the extent that Fort McKay First Nation frames LARP and MLAMP as elements of Crown consultation, section 21 of *REDA* prohibits the AER from assessing their adequacy;

(b) LARP prohibits decision makers, including the AER, from "adjourning, deferring, denying, refusing, or rejecting any application…" by reason only of incompletion of a LARP regional plan;

(c) the AER could not deny Prosper's application solely because MLAMP negotiations were not yet complete; and

(d) given that AER approval of an application made under section 10 of *OSCA* was subject to prior authorization by Cabinet, Cabinet was the most appropriate place for a decision on the need to finalize MLAMP.

The AER found that the following factors weighed on the positive side of the public interest balance for the Rigel Project:

(a) section 10 of the *OSCA* was clear that an application for an oil sands scheme may be approved if it is found to be in the public interest, but that such an approval is not a foregone conclusion;

(b) consistency in regulatory decisions was desirable, but each *OSCA* application must be assessed on its own merits and in light of the relevant regulatory, legal, and factual frameworks;

(c) in this case, Prosper made a concerted effort to minimize impacts of the Rigel Project, often committing to going beyond the minimum regulatory requirements and addressing concerns of the participants and others - all while maintaining substantial economic benefits for a project of its size;

(d) the purposes provisions of the *OSCA* read with the AER mandate provisions in *REDA* and the purposes provisions of *EPEA* and the *Water Act* were clear that the public interest lies in striking a balance between the economic benefits to Alberta and protecting the environment, promoting sustainable resource development, and ensuring the conservation and wise use of water; and

(e) Prosper's Rigel project struck that balance.

Based on the above, including the additional considerations, the AER found the Rigel Project to be in the public interest.

<u>*EPEA* Application</u>

For the reasons summarized below, the AER concluded that approving Prosper's *EPEA* Application was consistent with protecting the environment and promoting sustainable resource development while considering economic growth.

The AER found that:

(a) with the mitigations proposed by Prosper and the standard *EPEA* conditions for soil conservation, contamination, and monitoring, impacts on soils would be consistent with *EPEA* goals;

(b) long-term impacts of clearing vegetation were uncertain, and short-term impacts of vegetation loss during the life of the Project and until reclamation were unavoidable;

(c) the evidence did not suggest that the short-term impacts of the Rigel Project on vegetation were inconsistent with the purposes of *EPEA* or that they were likely to cause unacceptable ecosystem impacts; and

(d) Prosper's mitigation measures and compliance with the relevant regulatory provisions, would ensure that the expected effects on vegetation would not make the Rigel Project inconsistent with the purposes of *EPEA*.

The AER confirmed that the Rigel Project was not subject to the Alberta Wetland Policy because Prosper had completed the relevant filing requirements before the date that policy was implemented in the Green Zone of Alberta.

The AER found that, with Prosper's mitigation commitments, the Rigel Project was consistent with the purposes of the *EPEA*.

Air Quality

The AER explained that Prosper was required to comply with the Alberta Ambient Air Quality Objectives and Guidelines ("AAAQO") issued by Alberta Environment and Parks. To meet this requirement, Prosper conducted an air quality assessment to identify emissions associated with the Project. Prosper modelled expected maximum ground-level concentrations of sulphur dioxide (SO2), nitrogen dioxide (NO2), carbon monoxide (CO), and atmospheric particulate matter (PM2.5) associated with project operations.

The concentration of each pollutant was calculated and compared with the AAAQO. The results showed that air emissions from the Rigel Project were well below the applicable air quality objectives.

The AER found that the Rigel Project complied with all applicable AAAQOs.

Habitat Loss

The Rigel Project would be located about 64 km from Fort McKay, west of the Athabasca River. The AER noted that there was significant oil sands development and other resource and industrial development in the area.

The AER explained that it had to make its decision based on project-specific impacts, including the likelihood and severity of those impacts. A decision to halt resource and industrial development generally in an area (i.e. unacceptable regional cumulative effects, as suggested by Fort McKay First Nation), was a policy-level decision that the AER had no authority to make.

The AER determined that it was not able to conclude that the Rigel Project would cause loss of habitat resulting in permanent harm to the ecosystem in the Moose Lake area.

Reclamation

Under the *EPEA*, the goal of reclamation is to return areas disturbed for industrial development to equivalent land capability, which it defines as "….the ability of the land to support various land uses after conservation and reclamation is similar to the ability that existed before an activity being conducted on the land, but that the individual land uses will not necessarily be identical."

The AER found that Prosper's reclamation plans were reasonable and appropriate at this stage of project development.

Water Act Application

Introduction

The AER considered whether the proposed water withdrawals were consistent with the purpose of the *Water Act* and related guidelines, including the Water Conservation and Allocation Guideline for Oilfield Injection ("WCAGOI"). The AER explained that:

(a) the objective of the guidelines is to minimize the use of fresh water whenever possible;

(b) applicants needing water for oilfield injection must conduct a comprehensive assessment of available saline and nonsaline sources;

(c) applicants must also meet requirements in the Alberta Environment Guide to Groundwater Authorization, 2011 (AGGA); and

(d) applicants must justify the need for the water and confirm that the aquifer is capable of sustaining the amount of water required over the life of the project without adversely impacting other licensed users or existing households.

Application

Prosper's *Water Act* Application requested approval to use water from two existing water supply wells:

(a) 620 m3/d, or 226 300 m3/year, from the 8-20 well completed in the Deep Drift aquifer; and

(b) 80 m3/d, or 29 200 m3/year, from the 8-28 well completed in the Viking aquifer.

Total withdrawals would be 700 m3/d, or 255 500 m3/year, over the life of the Project, which is expected to be 25 years beginning in October 2019. The water is for steam production and utility purposes at the Rigel Project.

AER Findings

The AER found that:

(a) Prosper's examination of the potential impacts of its groundwater withdrawals was robust and reliable;

(b) the Deep Drift and Viking aquifers had sufficient sustainable yield to meet the needs of the project without affecting the integrity of the aquifers;

(c) with respect to saline alternatives:

  (i) taking water from the Cooking Lake aquifer (potential saline alternative) would create additional environmental and habitat disturbances;

  (ii) these disturbances would also cause more impacts on traditional land use for Fort McKay Métis and Fort McKay First Nation; and

  (iii) these impacts were significant and were not acceptable; and

(d) Prosper's withdrawals would not adversely impact the aquifers, the aquatic environment, or other licensed users; and

(e) the inclusion of surface water monitoring exceeded regulatory requirements for this type of application.

<u>Conclusion</u>

Based on the above and considering the conditions of approval, the AER determined the following:

- Prosper's Rigel Project was in the public interest, taking into account its expected impacts on Aboriginal and treaty rights and traditional land use, its expected social and economic impacts, its impacts on the environment, and its impacts on landowners;

- Prosper's *EPEA* Application to construct, operate, and reclaim the Rigel Project CPF and associated infrastructure was consistent with protecting the environment and promoting sustainable resource development while considering the need for Alberta's economic growth and prosperity; and

- Prosper's *Water Act* application was consistent with the conservation and wise use of water resources in Alberta, taking into account economic growth and prosperity, the need to maintain a healthy environment, and the effects of the proposed diversion on the aquatic environment.

ALBERTA UTILITIES COMMISSION

Sale and Transfer of the Municipality of Crowsnest Pass Electric Distribution Assets to FortisAlberta Inc. (Decision 21785-D01-2018)

Sale and Transfer of Utility Assets - Prudence of Purchase Price

In this decision, the AUC considered applications by FortisAlberta Inc. ("FortisAlberta") and the Municipality of Crowsnest Pass (the "Municipality") for the sale and transfer of the Municipality's electric distribution system. In addition, FortisAlberta requested that the AUC consider the reasonability, calculation and prudence of the purchase price of $3,745,902.

Summary

The AUC found that approval of the sale and transfer of the Municipality's electric distribution system was in the public interest. Accordingly, the AUC:

(a) approved the Municipality:

(i) to cease operations in its service area, pursuant to Section 29(1) of the *Hydro and Electric Energy Act* (*HEEA*);

(ii) to discontinue its electric distribution system operations under Section 30 of the *HEEA*;

and

(b) ordered the incorporation of the service area of the Municipality into FortisAlberta's service area, pursuant to Section 25 of the *HEEA*.

With respect to the purchase price, the AUC:

(a) found the use of the replacement cost new less depreciation methodology was reasonable in the circumstances; and

(b) approved the value of the applied-for replacement cost new amount.

However, the AUC did not find the applied-for depreciation amount to be prudent. Accordingly, the AUC did not find the applied-for purchase price to be prudent, for rate setting purposes.

Stage One: Public Interest

For the reasons summarized below, the AUC found that the transfer of the Municipality's electric distribution system to FortisAlberta was in the public interest.

In finding that the sale and transfer were in the public interest, the AUC considered the following:

(a) FortisAlberta already had assets and operations located within the Municipality's boundaries;

(b) there was an agreement with FortisAlberta to continue to provide service to the customers served by the Municipality and to operate, maintain, replace, reconstruct, alter or upgrade the facilities in accordance with the municipal franchise agreement; and

(c) the Municipality requested FortisAlberta to make a formal offer, and the council of the Municipality had passed a resolution unanimously to proceed with the sale of its electric distribution system and related assets to FortisAlberta.

Stage Two: Prudence of Purchase Price

With respect to its consideration of the prudence of the purchase price paid by FortisAlberta, the AUC explained that:

(a) under the *Electric Utilities Act* ("*EUA*"), the AUC must establish rates that provide a distribution utility, such as FortisAlberta, with a reasonable opportunity to recover its prudent costs to provide service to its customers;

(b) once the AUC determines the cost of an electric distribution system acquisition to be prudent, a distribution utility may apply to the AUC for an adjustment of its rates; and

(c) in this case, if the AUC were to find the purchase price to be prudent, then this would facilitate FortisAlberta's application to recover the purchase price in rates as part of its annual Performance-Based Regulation ("PBR") rate adjustment filing.

Use of Replacement Cost Method

FortisAlberta determined the purchase using a "replacement cost new, less depreciation" method, based on obtaining a "replacement" value in lieu of a "reproduction" cost.

The AUC found that, in the circumstances, FortisAlberta's use of the replacement cost new, less depreciation methodology was reasonable for the purposes of this decision, subject to the findings on the depreciation component calculations discussed below.

The AUC noted that section 29(4) of the *HEEA* refers to “reproduction cost new, less depreciation.” However, the AUC noted its previous findings that the use of a replacement cost new, less depreciation method was a reasonable alternative in certain circumstances.

The AUC found that the replacement cost methodology was reasonable in the circumstances, based on the following:

(a) determining the vintage of the assets and obtaining a reasonable cost estimate would be a labour-intensive task, had FortisAlberta chosen to use reproduction cost new methodology; and

(b) there was insufficient evidence to support the use of a “blended” valuation approach, which would combine both the replacement and reproduction cost new methodologies to evaluate the Municipality’s assets when compared to the replacement cost new, less depreciation methodology.

The AUC approved the replacement cost new value of $5,407,786, as reflected in the FortisAlberta proposal.

The following section summarizes the AUC’s findings regarding the depreciation component of the replacement cost new, less depreciation methodology

Depreciation

The AUC denied FortisAlberta’s request for a determination that the accumulated depreciation amount of $1,640,277 employed in the replacement cost new less depreciation methodology was prudent.

The AUC found that:

(a) FortisAlberta was proposing a 30.33 percent depreciation rate to be applied to Municipality assets that had reached or were near the end of their service life;

(b) this method did not provide a reasonable proxy for estimating the accumulated depreciation associated with the acquired assets, given the vintage of those assets being acquired.;

(c) the proposed depreciation component of $1,640,277 produced a value that was not commensurate with the value of the Municipality’s system.

Based on the above, the AUC concluded that it had insufficient evidence to determine which approach was suitable to calculate the depreciation component of the purchase price.

Condition of Approval

The AUC confirmed that the transfer of the Municipality’s electric distribution system could proceed irrespective of the AUC’s findings regarding the purchase price agreed-to in the asset purchase agreement.

However, given the AUC’s determination that it was not able to find the applied-for purchase price to be prudent, the AUC required as a condition of approval that: FortisAlberta and the Municipality shall advise the AUC within 90 days of the decision whether they intend to proceed with the sale and transfer of the electric distribution system and the agreed-to purchase price.

FortisAlberta may reapply in a compliance filing for approval of a revised purchase price determined on the basis of a comprehensive depreciation methodology that reflects the state of condition, vintage and necessity of the infrastructure assets to be acquired from the Municipality. Should the AUC find the revised purchase price to be prudent for rate setting purposes, then FortisAlberta would be free to use this determination in its application for purchase price recovery in rates as part of the annual PBR rate adjustment filing.

ATCO Gas, a Division of ATCO Gas and Pipelines Ltd. - Z Factor Application for Recovery of 2016 Regional Municipality of Wood Buffalo Wildfire Costs (Decision 21608-D01-2018)

PBR Plan - Z Factor - Wildfire - Asset Retirement - “Used or Required to be Used”

In this decision, the AUC considered ATCO Gas, a division of ATCO Gas and Pipelines Ltd.’s (“ATCO”) application to recover $11.199 million through a Z factor rate adjustment for the costs it incurred as a result of the 2016 Regional Municipality of Wood Buffalo wildfire (the “Wildfire”).

For the reasons summarized below, the AUC determined that:

(a) for 2016, all five of the criteria to qualify for a Z factor rate adjustment had been met;

(b) the Wildfire was of a similar nature and magnitude to other nature-related events identified in ATCO Gas’ 2009 depreciation study; and

(c) the Wildfire did not give rise to an extraordinary retirement of the destroyed assets.

Therefore, the depreciation expense associated with the assets that were replaced would continue to be recovered from ratepayers.

Performance-Based Regulation Plan and Z Factor

Background

The AUC set out the following regarding the performance-based regulation ("PBR") plans for the distribution utility services of certain Alberta electric and gas companies, including ATCO:

- Decision 20414-D01-2016 approved PBR plans for the Alberta distribution companies for a five-year term commencing January 1, 2018. In that decision, the AUC confirmed that the Z factor approach was to remain unchanged from that established in the first PBR plans Decision 2012-237.

- The PBR framework provides a formula mechanism for the annual adjustment of rates for those companies under an approved PBR plan. In general, rates are adjusted annually by means of an indexing mechanism that tracks the rate of inflation (I) relevant to the prices of inputs the companies use, less a productivity offset (X) to reflect the productivity improvements the company can be expected to achieve during the PBR plan period.

- Establishing prices in this way during the term of a PBR plan is intended to create stronger incentives for the companies to improve their efficiency because they are able to retain the increased profits generated by those cost reductions longer than they would under cost-of-service regulation.

- At the same time, under a PBR framework, customers automatically share in the expected productivity gains because they are built into rates through the X factor regardless of the actual performance of the companies.

With respect to the Z factor component of PBR plans, the AUC explained:

- The Z factor recognizes that, in competitive markets, exogenous factors that affect only the industry in question, such as an increase in taxes, would be passed through to customers by that industry in its market prices.

- The Z factor is intended to deal with significant events outside the companies' control that are specific to the industry and would not be reflected through the I factor.

- The Z factor can also be used to account for cost changes caused by unique company-specific events (such as floods or ice storms) outside the company's control and that are not reflected in the I factor.

- In Decision 2012-237, the Commission established the following criteria to be applied when evaluating whether the impact of an exogenous event qualifies for Z factor treatment:

    (1) The impact must be attributable to some event outside management's control.

    (2) The impact of the event must be material. It must have a significant influence on the operation of the company otherwise the impact should be expensed or recognized as income, in the normal course of business.

    (3) The impact of the event should not have a significant influence on the I factor in the PBR formulas.

    (4) All costs claimed as an exogenous adjustment must be prudently incurred.

    (5) The impact of the event was unforeseen.

- Z factors should be symmetrical in that they should apply to exogenous events with both additional costs that the company needs to recover and also reductions to costs that need to be refunded to customers.

Criterion 1 & 5: Impact Attributable to Unforeseen Event Outside Management's Control

The AUC found that the specific timing and location of the wildfire and its impact to the Fort McMurray area had an impact which was unforeseen and outside of management's control, thus satisfying the criteria for Z factor treatment related to an impact attributable to unforeseen events outside management's control.

Criterion 4: Exogenous Adjustment Must Be Prudently Incurred

The AUC considered whether the costs claimed as an exogenous adjustment, namely capital expenditures, operations and maintenance ("O&M") costs and lost revenue, were prudently incurred.

For the reasons summarized further below, the AUC found that:

(a) the scope of the work performed, the timing of the repair and replacement activity and the quantum of the capital costs to be prudent, subject to a minor correction identified by ATCO related to received insurance payment;

(b) O&M costs claimed for 2016 as an exogenous adjustment were prudent; and

(c) with respect to lost revenue:

(i) but for the wildfire, the customers with sites destroyed by fire (1,620), and the customers with sites materially damaged by fire and not inhabitable (440) would have remained as customers and ATCO Gas would have received revenues from these customers; and

(ii) accordingly, the revenue lost as a result of the wildfire for these customers was eligible for inclusion in the Z factor adjustment

ATCO's applied-for revenue requirement related to capital additions, O&M expenditures and lost revenue, included in this Z factor application, is set out in the table below:

Table: Components of the proposed exogenous adjustment

($ million)	
Revenue requirement related to capital additions	0.12
O&M expenditures	9.21
Lost revenue	1.87
Total	11.20

Capital Expenditures

Regulatory treatment of destroyed assets

The AUC determined that the destroyed assets should be treated as an ordinary retirement and accounted for accordingly, noting that no party disputed that, as a result of the wildfire, the destroyed assets were retired in the ordinary course of business.

The AUC held that whether a retirement is ordinary or extraordinary will turn on whether the event that destroyed the utility assets had been contemplated or anticipated by a prior depreciation study. An event will give rise to an extraordinary retirement if the characteristics of the event (e.g. fire) in question cannot be said to have been reasonably contemplated or anticipated in the determination of the depreciation parameters in the prior depreciation study (citing Decision 27388-D01-2016).

In this case, the AUC considered ATCO's history of losses due to natural disasters or other force majeure events similar in nature to the wildfire. In this regard, the AUC found that the replacement costs of the 2016 wildfire were $2.2 million, which were similar to the replacement costs of the 2005 flood and other nature-related events that were incorporated into the 2009 depreciation study.

The AUC directed ATCO, in the compliance, to provide all accounting entries reflecting the retirement of the assets destroyed by the wildfire. ATCO was also directed to indicate how the remaining net book value of the destroyed assets will be recovered from customers.

Utility Asset Disposition Principles: Used or required to be used

Section 37 of the *Gas Utilities Act* describes the assets that determine a gas utility's rate base as those assets that are "used or required to be used to provide service to the public."

In Decision 2013-417, known as the Utility Asset Disposition ("UAD") decision, the Commission considered the interpretation of "used or required to be used" by the courts, and made, *inter alia*, the following findings:

- The words "used or required to be used" in Section 37 of the *Gas Utilities Act* "are intended to identify assets that are presently used, are reasonably used, and are likely to be used in the future to provide services. The past or historical use of assets will not permit their inclusion in the rate base unless they continue to be used in the system."

- The "only reasonable reading of s. 37 is that the assets that are 'used or required to be used' to provide service are only those used in an operational sense."

- The effective date for removal of a gas utility asset from rate base and customer rates is the earlier of: (i) the date that the utility advises the AUC that the asset is no longer used or required to be used; or (ii) the date the AUC determines that an asset no longer has an operational purpose and is no longer used or required to be used to provide service to the public.

ATCO stated that it incurred $2.2 million in capital expenditures to repair, replace or alter mains and pressure regulating stations that were damaged in the wildfire. The costs incurred for related projects are summarized in the table below.

Table: Mains and Stations Project costs

Project	Capital expenditures ($000)
Mains Projects	
Repair of fire damaged areas	1,249
Beacon Hill North Replacement	161
Other mains projects	78
Mains projects total	1,488
Pressure Regulation Station Projects	
Fort McMurray Gate Station #1 Replacement	659
Saprae Creek Gate Station Repair	25
Pressure regulation station projects total	683
Total capital expenditures	2,171

Regarding mains, for those mains that supplied customers further along the line, the AUC accepted ATCO Gas's explanation that "While there may not be active services along some sections of a particular main, the full length of main needed to be repaired in order to maintain safe and reliable service to customers further along the line." The AUC further found that:

(a) evacuated residents were only permitted to return once certain reentry conditions were met, including the availability of essential services such as gas utility service;

(b) ATCO Gas would not have known when and if customers would return to the affected areas, and that it expected customers to return intermittently; and

(c) therefore, it was incumbent on ATCO Gas to meet its obligation to supply service to active sites located downstream of destroyed areas, as well as to inactive sites to ensure facilities were in place to provide gas utility service to customers when they returned.

Accordingly, the AUC found that, for 2016, the replacement assets including stations and mains were presently used, reasonably used and likely to be used in the future to provide service.

However, the AUC considered that it did have sufficient evidence to determine whether ATCO would have known when and if customers would return to the affected areas in 2017. The AUC therefore declined to make any determination as to whether all the mains were used or required to be used after 2016.

Given the uncertainty of whether all of the repaired and replaced mains and related assets would continue to be used or required to be used after 2016, the AUC directed ATCO to provide the following in its compliance filing:

(a) whether all or any of the mains and related assets that the Commission found were used or required to be used in 2016 continue to be used or required to be used after 2016;

(b) a map showing the locations of the mains or portions thereof, and related assets, that do not supply any customers;

(c) the net book value of mains or portions thereof, and related assets, that do not supply any customers;

(d) for the mains or portions thereof, and related assets, that do not supply any customers, and ATCO Gas submits are required to be used:

  (i) the month and year that ATCO Gas expects customers to connect to the main; and

  (ii) the basis of the forecast for the aforementioned month and year that ATCO Gas expects customers to connect to the main;

(e) with respect to the mains and related assets that the Commission found were used or required to be used in 2016, whether UAD principles apply after 2016 to exclude all or a portion of these mains and related assets from rate base after 2016; and

(f) if all or any of the mains and related assets that the Commission found were used or required to be used in 2016 were no longer used or required to be used in subsequent years, what adjustments to rate base were required, if any and when such adjustments would be made.

<u>O&M Costs</u>

ATCO stated that in 2016 it incurred incremental O&M costs and lost revenue of $11.1 million as a result of the wildfire.

The AUC found that:

(a) ATCO Gas worked diligently and effectively to ensure the safety of the gas distribution system, to support critical facilities during the event and to return gas utility service to its customers to facilitate the reentry of residents to evacuated areas; and

(b) the timing of these activities, the scope of the work completed, and the O&M costs of $9.2 million incurred in response to this event in 2016, to enable service, were reasonable.

The AUC concluded that the O&M costs claimed for 2016 as an exogenous adjustment were prudent.

Lost Revenue

The Z factor allows for an adjustment to a company's rates to account for the significant financial impact of an event outside of the control of management. This can include lost revenue. The event must not have an economy-wide impact. Otherwise the cost of that impact would be reflected and recovered in the I factor.

ATCO applied to recover $1,867,000 of lost revenue. ATCO calculated this lost revenue by comparing the actual rate revenue to the rate revenue forecast for the Fort McMurray weather zone for the eight-month period May 1, 2016, to December 31, 2016.

The AUC found that:

(a) but for the wildfire, the customers with sites destroyed by fire (1,620), and the customers with sites materially damaged by fire and not inhabitable (440) would have remained as customers, and ATCO Gas would have received revenues from these customers; and

(b) accordingly, the revenue lost as a result of the wildfire for these customers was eligible for inclusion in the Z factor adjustment, and would be recoverable if the Z factor materiality threshold was achieved.

However, with respect to 190 sites where the site itself was not destroyed or materially damaged, and the customer had not requested reconnection, the AUC found that there may be factors other than the wildfire that prevented these customers from returning. As such, the AUC determined that ATCO Gas may not collect the lost revenue calculated for these 190 sites, other than the revenue lost during the mandatory evacuation period.

The AUC directed ATCO Gas to recalculate lost revenue by excluding these 190 sites in its compliance filing.

Criterion 2: Materiality

In Decision 2012-237, the Commission approved a Z factor materiality threshold as the dollar value of a 40-basis points change in after-tax ROE, which was used to determine the revenue requirement for ATCO Gas' 2012 going-in rates. The threshold is to be adjusted annually by the I-X index.

ATCO Gas North's 2016 materiality threshold was $1.508 million. This threshold was approved in Decision 21606-D01-2016, for the purposes of ATCO's K factor calculation, which used the same 40 basis point ROE methodology for its calculation. In the application, ATCO noted that the earnings impact of $8.2 million from this event was in excess of the AUC approved materiality threshold.

The AUC found that ATCO Gas' Z factor was material, after accounting for adjustments directed elsewhere in the decision, given that ATCO Gas' applied-for Z factor adjustment of $11.2 million for costs incurred in 2016 significantly exceeded the approved 2016 materiality threshold of $1.508 million.

Criterion 3: Significant Influence on the Inflation Factor in the PBR Formula

The AUC considered whether the impact of the event had a significant influence on the inflation factor in the PBR formula.

In Decision 2012-237, the Commission held that "… providing the company with additional revenues through a Z factor adjustment in circumstances where the event has economy-wide impacts would result in a double-counting of the impact of the exogenous event."

The AUC found that there was insufficient evidence to conclude that the wildfire had a significant influence on the measures of inflation in Alberta included in the I factor and therefore, there was no double-counting of revenue if the Z factor were approved.

Conclusion

The AUC determined that ATCO's 2016 costs related to the wildfire experienced in the Regional Municipality of Wood Buffalo met all the criteria for Z factor treatment, subject to certain adjustments. Therefore, the AUC approved ATCO Gas' application to include the wildfire Z factor adjustment in its 2019 annual PBR rate adjustment.

Direct Energy Regulated Services - 2017-2018 Default Rate Tariff and Regulated Rate Tariff (Decision 22004-D01-2018)
Rates - Default Gas Tariff - Regulated Electricity Rate Tariff

Introduction

Direct Energy Regulated Services ("DERS") is a business unit of Direct Energy Marketing Limited ("DEML") and performs the natural gas default rate tariff ("DRT") and electricity regulated rate tariff ("RRT") functions in the service territories of ATCO Gas and Pipelines Ltd. ("ATCO Gas") and ATCO Electric Ltd. ("ATCO Electric"), respectively.

In this decision, the AUC considered, DERS' application requesting approval of its 2017-2018 DRT and RRT tariff for the January 1, 2017, to December 31, 2018 period ("Test Period").

The Application

DERS requested AUC approval of:

(a) the revenue requirements (DRT and RRT);

(b) DERS' proposed allocation methodology for corporate services costs; and

(c) resulting 2017-2018 rates on a final basis.

DERS requested approval of both the DRT and RRT revenue requirements. The revenue requirements were, segregated into energy-related and non-energy revenue requirement components, as well as an RRT risk margin and a DRT retail margin as follows:

- A DRT non-energy revenue requirement of $59.4 million in 2017 and $57.8 million in 2018;
- An RRT non-energy revenue requirement of $19.0 million in 2017 and $17.9 million in 2018;
- A DRT energy-related revenue requirement of $2.5 million in 2017 and $2.3 million in 2018;
- An RRT energy-related revenue requirement of $0.5 million in 2017 and $0.3 million in 2018;
- DRT retail margin revenue of $8.4 million in 2017 and $8.1 million in 2018; and
- RRT risk margin revenue of $5.9 million in 2017 and $5.8 million in 2018.9.

Decision Overview

In assessing DERS' application, the AUC considered the following:

- customer site forecasts and corresponding load forecasts;
- forecasted estimates for non-labour inflation, labour inflation, energy transmission and distribution ("T&D") rates in its service areas, and natural gas prices and forward market electricity prices;
- planned capital expenditures for 2017 and 2018;
- each of the specific cost categories making up the applied-for total energy and non-energy revenue requirement amounts; and
- DERS's request for DRT retail margin revenues for 2017 and 2018, and for RRT risk margin revenue for 2017 and 2018.

Customer Site and Load Forecasts

The AUC confirmed its findings from previous decisions that updated information may be used for evaluating the reasonableness and accuracy of the forecasts and forecast methodologies. This can include information that becomes available during the course of a proceeding.

DERS' customer site forecasts for 2017 and 2018 were derived using a methodology that incorporated actual data from April 2014 through March 2017.

Given that DERS would now have actual data for 2017 and at least for the first four months of 2018, the AUC directed that DERS use the following actual data and/or forecast methodologies:

(a) for 2017, the actual site counts and customer load amounts;

(b) for Jan-Apr 2018, actual site counts and load amounts;

(c) for the remaining May-Dec 2018:

   (i) site count forecasts based on actual data from the preceding 36-months; and

   (ii) customer load forecasts developed using the average usage per site amounts included in the application (based on 10-year average weather figures).

The AUC noted that the Alberta government instituted a price cap, which took effect June 1, 2017, which caps the regulated rate option ("RRO") rate at 6.8 cents per kilowatt hour (kWh) for electricity, or the market rate, whichever is lower, until May 31, 2021.

DERS' customer site forecasts for 2017 and 2018 were based on projections from data before the price cap. The AUC considered use of more recent RRT site data would reflect initial changes in customer site growth and attrition rates attributable to the price cap.

In addition, some sites in Fort McMurray were destroyed as a result of the 2016 fire, and the rebuild schedule is unclear. The AUC considered that the use of more recent RRT and DRT site data would incorporate actual rebuilds that have occurred in Fort McMurray.

<u>Other Forecasting Parameters: Inflation, T&D Rates, and Forward Energy Prices</u>

The AUC accepted DERS' 3.13 per cent labour increase for 2017.

The AUC directed DERS to update its 2018 labour forecasts based on the three-year average (2015-2017) of actual labour increases.

With respect to inflation, the AUC found that:

(a) the inflation rate data relied on by DERS might not reflect current market conditions;

(b) during the course of the proceeding, actual inflation rates for 2017 became available; and

(c) the inflation rates may be trending downward.

The AUC directed DERS in its compliance filing:

(a) to use actual CPI inflation rates and commodity prices for 2017;

(b) for 2018, to incorporate the most recent CPI and commodity price forecasts at the time of filing its compliance filing to this decision; and

(c) to reflect the updated inflation rates in its compliance filing to this decision for any forecasts that apply inflation rates.

With respect to the data relied on to determine T&D rates, the AUC directed DERS:

(a) to use the actual T&D rates for the RRT and the DRT for 2017, to derive the forecast T&D charges for 2017; and

(b) to use the current T&D rates for the RRT and the DRT (at the time of this decision) in deriving the forecast T&D charges for 2018.

<u>DRT and RRT Revenue Requirement Cost Categories</u>

Overview

The DRT and RRT non-energy revenue requirements consist of the following cost categories: customer operations, merchant fees, working capital, deemed income tax, credit charges, hearing cost reserve account, bad debt expense, penalty revenue, revenue offsets, unknown customer costs, full-time equivalents (FTEs) and labour costs, amortization of capital, customer information costs, other administration costs and corporate services.

The forecast for these cost categories for 2017 and 2018 was dependant on a number of forecast costs, that would require revision as a result of AUC's directions respecting forecasting data and methodology, as set out in this decision.

This summary addresses findings of interest regarding customer operations, bad debt, and revenue offsets.

Customer Operations

Customer operations include the costs associated with providing customer contact centre services, calculating, printing and delivering bills, and processing payments. DERS categorized the customer operations costs into the following:

(a) customer care and billing ("CC&B");

(b) bill delivery;

(c) paper, long distance and requests for service (RFS); and

(d) customer goodwill credits.

DERS forecast customer total operations costs of $49.1 million in 2017 and $48.7 million in 2018, a decrease from 2016 costs of $51.2 million. DERS said the decrease was mainly due to the reduction in the expected goodwill credits paid to customers and the reduction in customer sites.

Customer care and billing

The Commission found that:

(a) the fair market value ("FMV") of $4.77/month/site that was approved for 2016 should remain in place for 2017 and 2018, less than the $4.82 FMV rate proposed for 2018; and

(b) the $4.77/month/site rate for 2017 and 2018 amounts to prudent cost recovery for DERS and ensures that customers are not paying for CC&B services not yet up to full performance standards.

The AUC directed DERS, in its compliance filing, to forecast CC&B costs for 2017 and 2018 using a monthly rate of $4.77 per customer site.

Customer Goodwill Credits

DERS explained that the high level of goodwill credits paid to customers in 2016 was primarily the result of challenges experienced with DERS' billing services. DERS acknowledged that the allowable limit of credits provided to contact centre agents and supervisors was temporarily increased in 2016 while DERS dealt with a high number of escalated complaints. In addition, DERS explained that the goodwill credits paid in 2016 included credits for customers impacted by specific billing issues.

For the Test Period, DERS forecasted combined DRT and RRT goodwill credits of $0.3 million for 2017, and $0.2 million for 2018.

The AUC expressed concerns about the lack of support for increases in goodwill credit forecasts.

Recognizing DERS' current billing system limitations, the AUC approved a nominal amount of $25,000 in each of 2017 and 2018 for charge reversals, allocated 80 percent to the DRT and 20 percent to the RRT.

Bad debt expense

Bad debt expenses forecast by DERS were broken down into three categories: bad debt, collection agency costs and cut-off for nonpayment ("CONP").

DERS forecated bad debt expense using actual bad debt costs for recent years expressed as a percentage of total revenues. The forecast percentages for 2018 were derived using the historical percentages for 2013 and 2014. DERS stated that 2013 and 2014 were operationally stable years with more positive economic conditions, and therefore they would be the best years to use for the expected bad debt performance in 2018.

The AUC found that:

(a) the drivers of DERS' bad debt forecasts were likely unrelated to the third-party service provider's past performance and instead, were primarily due to changes in the economy; and

(b) there was insufficient evidence on the record to conclude that the CC&B service quality and performance issues were the driver for increased bad debt costs, as argued by the customer groups.

The AUC directed DERS, in the compliance, to update the forecasts for 2017 and 2018 for CONP using the 2016 actuals and applying the non-labour inflation rates.

The AUC approved the following percentages of revenue for forecasting bad debts and collection agency costs for 2017 and 2018:

- Forecasting bad debts costs for the DRT:
  - 2017 at 0.70 percent; and
  - 2018 at 0.64 percent;
- Forecasting collection agency costs for the DRT:
  - 2017 and 2018: at 0.13 per cent.

The AUC directed DERS to use these percentages in its compliance filing and apply them to the updated total revenue figures for 2017 and 2018.

Revenue offsets

Revenue offsets include fees charged by DERS directly to customers for items such as connections, i.e., new accounts and moves, reconnections and dishonored cheques.

The AUC denied DERS' proposal to eliminate the retailer reconnection fee as of May 1, 2018. The AUC considered that until DERS received approval to eliminate the retailer reconnection fee as part of an application to amend its approved terms and conditions, the retailer reconnection fee was still a valid Commission approved charge that must be applied by DERS in accordance with the approved terms and conditions.

Working capital

The need for working capital is a result of the lag between the payments to suppliers and the receipt of revenues from customers. DERS defined its working capital revenue requirements as "… the carrying costs in support of DERS' daily operations."

The AUC approved the results of the lead-lag study and the resulting lag days that DERS used in its calculation of the forecast working capital costs for 2017 and 2018. The AUC considered that the methodology DERS used to forecast its working capital was reasonable and consistent with well established practice in the utility industry in Alberta.

Centralized Corporate Services and Allocation Methodology

Allocation Methodology

Direct Energy ("DE") allocates corporate service costs to DERS for centralized support and administrative functions received from DE. DERS engaged KPMG LLP ("KPMG") to undertake a corporate services stand-alone study in late 2015 to establish the total annual costs that would be required to replace the centralized support and administrative functions services received by DERS if DERS was a stand-alone entity.

Corporate services costs were allocated to DERS from DE in two phases. In the first phase, total DE corporate shared service costs are allocated to all DE subsidiaries, divisions, and lines of business ("LOB") in three steps as outlined below:

- Step 1: Direct charges - removes and assigns costs that can be directly tied to an LOB. This includes costs that directly accrue to an LOB, all operations and depreciation cost centres and all corporate cost centres, which are 80 per cent or higher, attributable to a single LOB.

- Step 2: Driver based charges - includes allocation of remaining corporate shared services costs that can be associated to LOBs based on specific drivers determined by DE. Drivers include head count, per cent time spent on certain activities, and server count.

- Step 3: Indirect allocations - allocation of the remainder of corporate shared services costs are based on modified operating profit, which is an internal DE measure defined as contribution margin less direct charges.

In the second phase, the corporate costs allocated to North American Home in the first phase are then allocated to DERS. For shared service costs that apply to the regulated business, DERS determines if those costs should be allocated using a driver-based methodology or an indirect allocator.

80 percent and 20 percent of DERS' share of corporate service costs were then allocated to the DRT and the RRT, respectively, based on the split of DRT sites to RRT sites, which has a historic ratio of 80/20.

Based on this allocation method, DERS reported forecast corporate service costs of $4.772 million in 2017 and $4.872 million in 2018.

AUC Findings re Corporate Services Costs and Allocation Methodology

The AUC said that it generally agreed that in large corporate organizations, efficiencies are gained by centralizing certain shared services such as human resources, information technology and finance, which can be shared among subsidiaries and affiliates.

The AUC approved the total amount of corporate costs for 2017 and 2018, given that this was a new corporate costs allocation methodology and DERS provided some explanation concerning the proposed allocators.

The AUC went on to specifically consider DERS' supporting information for its allocation methodology. The AUC noted its direction from Decision 2957-D01-2015 that DERS "… provide further explanation and details of the actual costs, the rationale to support the cost allocators for each service, the volume of work received by DERS, the mechanism for tracking actual corporate costs and the associated variances in its next DRT and RRT application."

The AUC found that the level of transparency directed in Decision 2957-D01-2015 had not been provided to its satisfaction. The AUC therefore directed DERS to provide further explanation and details of the actual costs, the rationale to support the cost allocators for each service, the volume of work received by DERS, the mechanism for tracking actual corporate costs and the associated variances in its next DRT and RRT application.

Reasonable Return and Non-Energy Risk Margin

DERS Request for a non-energy risk margin

In requesting a non-energy risk margin, DERS submitted that it has significant risk in respect of its forecast for non-energy costs. DERS defined non-energy risk as the "… risk DERS faces as a result of external factors that create unfavourable and unreasonable exposure to additional costs that could not have been reasonably forecast." DERS categorized its risks into three areas:

(a) energy price and load,

(b) site attrition, and

(c) unexpected costs (e.g. unforeseen natural disasters such as floods and forest fires).

Commission Findings: Non-energy risk margin

The AUC noted that:

(a) the *Regulated Rate Option Regulation* expressly provides that reasonable return is to be exclusive of a risk margin pursuant to Section 5(1)(b)(ii); and

(b) there was no similar provision in the *Gas Utilities Act* or the *Default Gas Supply Regulation* that requires the setting of a risk margin separate from return, nor is there a prohibition against setting a risk margin separate from the return margin.

The AUC considered that DERS' application addressed both the DRT and RRT and DERS had chosen to apply for non-energy risk margins for both the default gas supply and the RRO.

The AUC denied DERS' request for non-energy risk margin revenue for 2017 and 2018 for the DRT and the RRT, based on its finding that all of these risks identified by DERS related to the energy operations of the RRT, and not to the non-energy operations of DERS' RRT.

The AUC therefore directed DERS, in its compliance filing, to exclude any non-energy risk margin revenue.

DRT reasonable return

Section 6(1)(b)(i) of the *Regulated Rate Option Regulation*, provides that an RRT must allow for a reasonable return for the obligation on the RRO provider to provide electricity services. As a result, the RRO providers are permitted to charge customers an amount for a reasonable return for service.

Section 5(a) of the *Default Gas Supply Regulation* provides an equivalent provision with respect to default gas suppliers.

The AUC found that both regulations required it to set a reasonable return.

Reasonable return for DRT

The AUC considered that DERS' evidence had not sufficiently supported the use of the requested $0.034/GJ figure amount. The AUC found that due to the lack of support for $0.034/GJ, and given the lack of any alternatives, the methodology and percentage approved for 2012-2016 to determine the DRT reasonable return charge should be used for 2017-2018.

NATIONAL ENERGY BOARD

NOVA Gas Transmission Ltd. Application for Approval of 2018-2019 Revenue Requirement Settlement and Final 2018 Rates, Tolls, Charges and Abandonment (Letter Decision and Order TG-004-2018)
Natural Gas Pipeline - Tolls and Tariff - Revenue Requirement - Settlement

Background

On 23 March 2018 NOVA Gas Transmission Ltd. ("NGTL") filed an application for approval of the 2018-2019 Revenue Requirement Settlement (the "Settlement") and Final 2018 Rates, Tolls, Charges and Abandonment Surcharges for the NGTL System (the "Application").

For the reasons summarized below, the NEB approved the 2018-2019 Settlement, as filed as a package, and the applied-for final 2018 tolls and 2018 abandonment surcharges.

The Application

In the Application, NGTL stated that:

(a) it calculated its revised 2018 interim rates in accordance with the Settlement and the existing rate design methodology approved in Order TG-004-2010 2018;

(b) abandonment surcharges were calculated using the Board approved methodology from the MH-001-2013 Reasons for Decision; and

(c) the Tolls, Tariff, Facilities and Procedures Committee ("TTFP") endorsed, through an unopposed resolution, the Settlement.

Decision Overview

In the Application, NGTL stated that the components of the 2018 – 2019 Settlement were inextricably linked and were presented to the Board as a package.

The NEB assessed the Application in this context rather than making a determination on the individual elements in the revenue requirement. The NEB's decision addressed the following:

(a) the Settlement Process,

(b) 2018 Revenue Requirement and Rates,

(c) 2017 Depreciation Study, and

(d) NGTL's Settlement Requirements to the Board.

Although not part of the Settlement, the Board also addressed the 2018 Abandonment Surcharges, and potential effect of approving this Application on the Board's March 8, 2018 Examination Decision concerning Northeast British Columbia competition matters.

Settlement Process

The Board found that:

(a) the TTFP negotiating process was open, and parties had a fair opportunity to participate in the negotiations;

(b) adequate information was placed on the record to allow the Board to assess the reasonableness of the Settlement and to determine if the resulting tolls were just and reasonable and not unduly discriminatory; and

(c) the settlement process employed by the TTFP to negotiate the 2018-2019 Settlement complied with the Board's Guidelines.

In addition to approving the Settlement, the NEB expressed its concerns with NGTL's view that a party should only be able to advise the Board of its opposition to a settlement if it votes "hard opposed" on a resolution in TTFP process.

With respect to the importance of comments in the regulatory process, the NEB explained that comments from interested parties to a settlement:

- may assist the Board in carrying out its adjudication function; and

- may be an indicator of emerging issues in a company's revenue requirement and may go beyond issues in a settlement.

The NEB further noted that NGTL's annual revenue requirements had been determined by an uninterrupted series of negotiated settlements since 2010 and there had been no Board proceeding to examine NGTL's revenue requirement in-depth.

Accordingly, the NEB further found that:

(a) interested parties to settlements should have the freedom to file comments without being encumbered by TTFP procedures, such as the requirement to take a "hard opposed" position in order to file comments with the NEB;

(b) NGTL's suggested procedural approach was overly confining and not supportive of the collaborative intent of the TTFP;

(c) NGTL appeared to be unintentionally extending the applicability of TTFP procedures so that the comment step in the Board's assessment process may no longer be meaningful; and

(d) applying the TTFP procedures as NGTL proposed may discourage parties from filing comments with the Board or, alternatively, may prompt more hard opposed votes simply to gain the ability to have the right to file a comment with the Board. Neither outcome enhances the effectiveness of the collaborative process.

The NEB concluded that:

> If the hard oppose condition for comments from parties to the Board is not enforced rigidly, the Board will continue to assess the weight to be given to such comments on an individual basis in each proceeding.

2018 Revenue Requirement and Rates

The Board approved the Settlement and the resulting 2018 revenue requirement as a package, based on finding the applied-for 2018 final tolls to be just and reasonable and not unduly discriminatory.

The Board noted that NGTL's current tolling methodology may be revised by a future Board decision.

2017 Depreciation Study

The Board approved NGTL's depreciation methodology proposed in its 2017 Depreciation Study and the use of the results to calculate the depreciation expense for 2018 and 2019.

The Board noted that its initiatives arising from the NEB March 8, 2018 Examination Decision may result in NGTL's depreciation principles and practices being reviewed further later in 2018 or in 2019.

NGTL's Settlement Reporting Obligations to the Board

The NEB set out the following TTFP reporting requirements from the Settlement:

(a) By March 31, 2019 (for 2018) and by March 31, 2020 (for 2019), NGTL will provide:

  (i) Supplemental Schedules to the TTFP in the prescribed form (the "Supplemental Schedules"); and

  (ii) an update to the TTFP on the pipeline integrity and compressor repair and overhaul activities and costs;

(b) On a quarterly basis, NGTL will provide the TTFP with detailed information on capital projects in the prescribed form;

(c) During the term of the Settlement, NGTL will provide the TTFP with variance updates for the Annual Plan (as defined in NGTL's Gas Transportation Tariff) projects forecast to be in excess of $25 million; and

(d) NGTL will file with the NEB the Supplemental Schedules and any updates related to items referred to in Sections 2(F)(ii) and (iv) by March 31, 2019 (for 2018) and March 31, 2020 (for 2019).

In addition, the NEB directed NGTL to provide the NGTL System unit transportation cost data in the Annual Plan for three historical years and the five forecast years covered in each year's Annual Plan (The unit transportation cost will be calculated by dividing NGTL's actual or forecast revenue requirement by the system's annual throughput, actual or forecast).

This filing requirement will take effect with NGTL's filing of its 2018 Annual Plan with the Board, which is expected in December 2018.

The NEB requested this data to enable the Board to have a better understanding of NGTL's capital spending program and its impact on NGTL's investment base and financial position. The unit transportation cost forecasts would enable NGTL's shippers and the Board to better understand the potential toll impacts on the NGTL System and its shippers.

2018 Abandonment Surcharge

The NEB approved NGTL's applied-for final 2018 daily abandonment surcharge of $0.0091/GJ/d that were calculated using the Board approved methodology from the MH-001-2013 Reasons for Decision. NGTL will place the funds collected in a trust approved by the Board for future abandonment costs.

Potential Effects of this Decision on the Filing Requirements from Examination Decision re: Northeast British Columbia Pipeline Competition

In the Examination Decision, the NEB directed NGTL and Westcoast to file information on capital spending policies for system extensions and expansions, depreciation policy, and tolling methodology and tariff provisions with their applications for 2019 final tolls. NGTL indicated that the analyses would be part of its application for 2019 Final Rates and changes resulting from the analyses would likely be implemented prospectively.

Summary re Decision and Order

The Board approved the 2018-2019 Settlement, as filed as a package, and the applied-for final 2018 tolls and 2018 abandonment surcharges and issued Order TG-004-2018 that gave effect to this decision.