Canadian Power

Key Developments in 2018

Trends to Watch for in 2019

The **Power Group at McCarthy Tétrault LLP** is pleased to present Canadian Power – Key Developments in 2018 – Trends to Watch for in 2019. It is our fourth annual Canadian power industry retrospective. This publication is intended to provide an overview, at both the regional and national levels, of the most significant developments in the Canadian power sector in 2018, including in the areas of environmental law, aboriginal law, sovereign risk, mergers & acquisitions and energy litigation, and to highlight key trends to watch for in 2019. We hope that you will find this publication to be both interesting and informative.

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REGIONAL PERSPECTIVES

British Columbia Regional Overview

Authors: Sven Milelli, Brianne Paulin, Maureen Gillis, Robin Sirett, Morgan Troke, and Michael Alty

Introduction

2018 proved to be a year of transition for BC's power sector. With the BC government and BC Hydro embarking on a wide-ranging review of energy policy and markets, utility models, and emerging technologies, most remaining energy procurement activities were suspended. Meanwhile, energy project activity in the province made several important strides, with positive final investment decisions for two liquid natural gas ("LNG") export projects and progression toward key construction milestones for BC Hydro's 1,100 MW Site C Clean Energy Project ("Site C Project") as it targets a 2024 in-service date. The provincial government also finished off the year by announcing its CleanBC climate strategy, aimed at further electrifying the province's large industrial operations. Together with new load sources from emerging sectors including LNG, cannabis, data centres and blockchain technology, these developments offer a glimmer of new hope for project development opportunities in 2019 and beyond.

Site C Project Update

In the wake of the provincial government's decision in December 2017 to complete construction of the Site C Project, development and construction work has proceeded and the project's foundation structure was completed in October 2018. Although geotechnical issues have resulted in a one-year delay in the diversion of the Peace River originally scheduled for September 2019, BC Hydro recently reached an agreement with its main civil works contractor that is expected to enable BC Hydro to meet current project milestones on schedule.

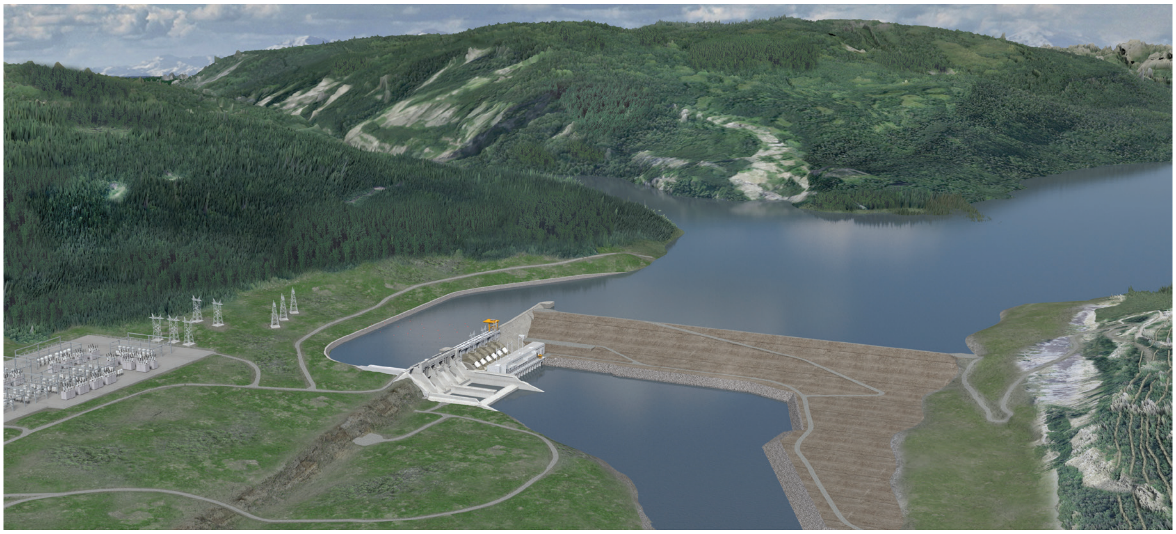
In addition to approximately $2.9 billion already spent on construction and related activities, BC Hydro has made financial commitments totaling approximately $6 billion, including service contracts with third parties, out of a total project budget of $10.7 billion. In its latest report, BC Hydro disclosed that there were 3,681 workers on the Site C Project, of whom 80% were from BC. Over 700 workers on site are from the Peace River Regional District, equivalent to 24% of the local construction and non-construction contractor workforce.

In October 2018, the BC Supreme Court denied an injunction application brought against the Site C Project by the West Moberly First Nation in connection with proceedings commenced in January 2018 asserting that the project unjustifiably infringes First Nation treaty rights. In its conclusions, the Court noted that "if an injunction is granted but the claim turns out to be unsuccessful on the merits, one of the most important public infrastructure projects undertaken in decades will be needlessly put into disarray." Further analysis of this decision can be found in our aboriginal law article on page 42 of this publication.

In dismissing the application, the Court directed the parties to agree on a schedule that would lead to a conclusion of the trial of the underlying treaty infringement action by no later than mid-2023. This timing would coincide with the completion of Site C Project construction but be prior to the reservoir flooding scheduled for the fall of 2023.

On December 20, 2018, BC Hydro announced that it has shortlisted three companies for the Site C dam's balance of plant contract, which includes the electrical, mechanical, and various civil and structural work required to complete the construction of the generating station and spillway, along with other related facilities.

The Site C Project will be the third dam and hydroelectric generating station on the Peace River in northeast BC, and following its expected in-service date of 2024 will provide 1,100 MW of capacity and about 5,100 GWh of electricity each year – enough to power the equivalent of about 450,000 homes. In accordance with the province's *Clean Energy Act*, Site C would be the last major hydroelectric project to be undertaken by BC Hydro.



Site C Project Rendering. Source: BC Hydro

CleanBC Strategy To Drive Electrification

The BC government announced its CleanBC climate strategy plan on December 5, 2018, setting out a pathway to achieve its target of reducing greenhouse gas emissions by 40% by the year 2030 (based on 2007 levels) as set out in the *Climate Change Accountability Act*. As part of this plan, the BC government will support clean natural gas production in the Peace Region through electrification and increase access to clean electricity for large industrial operations. Initiatives for a cleaner industry through electrification in the CleanBC strategy represent a total expected reduction of 3.5 Mt of GHG emissions by 2030. Additional commentary on this plan can be found in our environmental law article on page 29 of this publication.

To reach these targets, the BC government expects that this strategy will require an additional 4,000 GWh of electricity above the current projected demand growth. This would require increasing BC Hydro's current system-wide capacity by around 8%, which according to the CleanBC plan can be achieved through existing and planned renewable energy projects. In order to reach such electrification targets, BC Hydro will undertake a "transformational review" that addresses "changing energy markets, new utility models and emerging technologies to deliver on CleanBC's longer-term electrification goals". See "BC Hydro Update—Review by BC Government" below.

The BC government continues to pursue efforts to electrify the natural gas sector in the Peace Region of British Columbia. Some projects currently in place include the Dawson Creek/Chetwynd Area Transmission Project, which has doubled electricity capacity in the area, and the Peace Region Electricity Supply project, which is currently in progress, which will also bring increased electricity capacity in the region.

Finally, a key part of the BC government's climate strategy is the electrification and introduction of zero-emission light-duty cars and trucks ("ZEVs"). The BC government's current target is that all new light-duty cars and trucks will be ZEVs by 2040, with a target of having 10% ZEV sales by 2025 and 30% ZEV sales by 2030.

BC Hydro Update

REVIEW BY BC GOVERNMENT

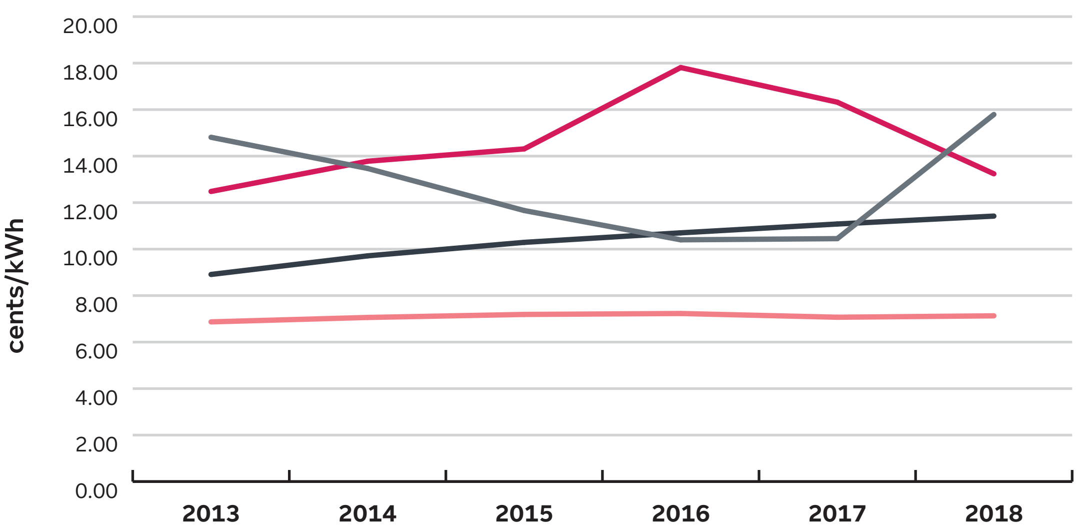
In June 2018, the BC government announced that it would be conducting a comprehensive, two-phase review of BC Hydro ("BC Hydro Review"). The first phase of the review will examine ways in which BC Hydro can cut costs and create new revenue streams to keep rates low, and will assist BC Hydro in preparing its rate application to the British Columbia Utilities Commission ("BCUC") to be filed in February 2019. The second phase of the review will focus on the transformational aspects of changing energy markets and respond to the BC government's anticipated Energy Road Map for BC, as well as assist BC Hydro in developing its Integrated Resource Plan in 2019.

The first phase of the review is being conducted by a panel of staff from government ministries and BC Hydro. The review was expected to be published by the end of 2018; however, as of the time of printing, the first phase report had not been released. As discussed below, BC Hydro has suspended its remaining energy procurement processes and will not enter into new EPAs, or confirm the renewal or extension of existing EPAs, pending the completion of the BC Hydro Review.

BCUC REJECTS F2019 RATE FREEZE

A key element of the BC Hydro Review's first phase will be the development of a new 10-Year Rates Plan, with the goal of reducing rate growth while ensuring sound financial and regulatory oversight of BC Hydro. These competing imperatives were brought into sharp relief in March 2018, when the BCUC rejected BC Hydro's proposed rate freeze for fiscal 2019. Having originally proposed a 3% rate increase in line with the previous government's 10-Year Plan, BC Hydro was directed by the new government to amend its BCUC submission to freeze its rates for the upcoming year. The BCUC rejected this change, concluding that there was not sufficient regulatory justification for approving real rate decreases and citing, among other factors, the recent history of rate increases (in nominal and real terms), the risk of additional upward pressure on future rates, and the concerns of growing deferral and regulatory accounts due to BC Hydro's load forecast and cost of energy.

Residential Electricity Prices, excluding taxes
(2013- 2018)



	2013	2014	2015	2016	2017	2018
Montréal, QC	6.87	7.06	7.19	7.23	7.07	7.13
Calgary, AB	14.81	13.41	11.66	10.40	10.45	15.79
Toronto, On	12.48	13.78	14.31	17.81	16.32	13.24
Vancouver, BC	8.91	9.71	10.29	10.70	11.08	11.42

Source: Hydro-Québec

AUDITOR GENERAL TARGETS BC HYDRO DEFERRAL ACCOUNTS

In August 2018, BC's Auditor General raised concerns about BC Hydro's deferral accounts that resulted in a qualification in the BC government's year-end financial report. At issue are the approximately $5.5 billion in expenses that BC Hydro has transferred into deferral accounts to be paid by ratepayers in future years. Although a common practice among North American utilities to prevent or smooth out rate increases, the Auditor General noted that the acceptability of such measures under accounting rules is contingent on independent regulatory oversight, in this case by the BCUC. Citing the previous government's cabinet orders overriding the BCUC to set BC Hydro's rates directly, resulting in limited rate increases and a corresponding expansion of BC Hydro's deferral accounts, the Auditor General continues to urge the BC government to more fully adopt practices justifying rate-regulated accounting. In response to these concerns, the BC government announced an adjustment of $950 million in its Public Accounts to reduce BC Hydro's deferral accounts, and noted that its BC Hydro Review would address future energy rates, regulatory accounts and the role of the BCUC.

FOCUS ON ATTRACTING NEW LOAD

In response to the combination of a forecast energy surplus for many years to come and declining industrial transmission-service load, BC Hydro is undergoing a significant shift and turning its focus to attracting new load and diversifying its industrial customer base. To incentivize new large industrial customers to locate in British Columbia, BC Hydro is developing load-attraction-rate pricing that will provide discounts to default firm-service rates in an effort to attract new customers that would not otherwise locate in British Columbia, thereby competing with utilities such as Hydro-Québec, which offers discounts to new and expanding facilities over 1 MW, and Manitoba, which offers North America's lowest large-power customer rates. In considering how to structure its load-attraction rate, BC Hydro is weighing factors such as how to optimize the locations of new load and how to avoid undermining the competitiveness of existing customers that would not be eligible for the discounted rate, which is currently proposed to apply only to new customers.

In addition to traditional mainstay industries in the province such as forestry and mining, BC Hydro is seeking to attract customers in new and growing industries such as cannabis, LNG, data centres, and blockchain technology—the latter used for energy-intensive cryptocurrency mining. Reportedly, BC Hydro has already received more than 10,000 MW of inquiries from interested prospective customers, almost half of which have been from the cryptocurrency industry, followed by LNG and cannabis.

After receiving industry input, in November 2018 BC Hydro previewed a proposed load-attraction rate design that would feature a fixed 15% discount to the standard transmission-voltage account ("RS 1823") energy and demand rate for a 5-year term or a fixed 20% discount to the RS 1823 energy rate only for a 5-year term. BC Hydro's financial modelling of the discount rate, based on an assumption of 20 MW new load starting in the 2020 financial year, indicates that there would be a net benefit to all BC ratepayers after accounting for marginal costs whether the new load stays in BC or departs after the discount period ends, indicating that BC Hydro should not need to screen prospective customers for longevity. Proposed eligibility criteria include a requirement that electricity costs constitute at least 10% of the prospective customer's operating costs, that rate be a determining factor in the customer's decision to locate in BC Hydro's service territory, and that the customer would not directly compete with existing customers paying standard industrial rates. BC Hydro expects to make an application to the BCUC for new load-attraction rates, as well as load-retention rates, in early 2019, and anticipates BCUC approval by mid-2019.

Electricity Procurement In 2018: Still On Hold

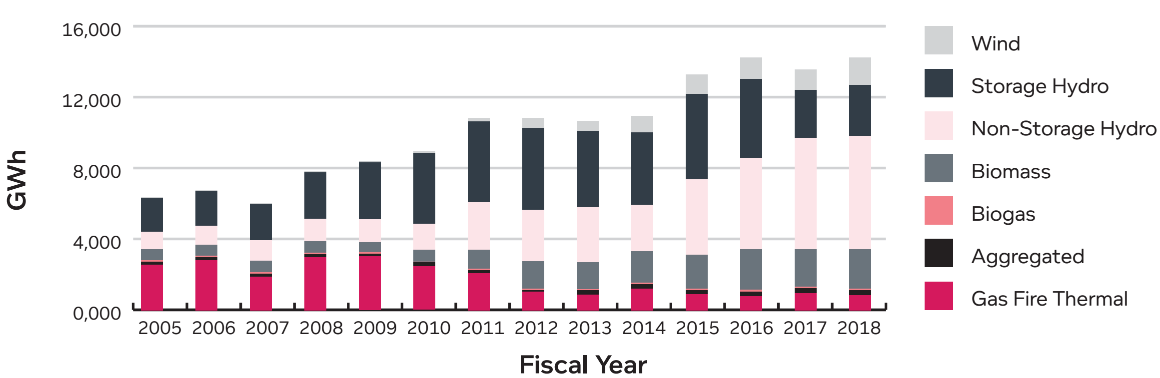
No new electricity procurement opportunities were announced in BC in 2018, and BC Hydro confirmed that it would not issue any new EPAs until the completion of the BC Hydro Review.

BC Hydro also confirmed that the moratorium on the Standing Offer Program ("SOP") and Micro-Standing Offer Program ("Micro-SOP") announced in August 2017 would remain in place until the BC Hydro Review is completed. In response to concerns by project developers regarding the costs of continuing interconnection studies on SOP projects, BC Hydro has obtained BCUC approval for an interim moratorium on relevant Open Access Transmission Tariff ("OATT") provisions to allow for the temporary suspension of interconnection work while the program is under review. All pending SOP projects will maintain their queue position until the BC Hydro Review is completed.

Notwithstanding its continuing moratorium on EPAs, BC Hydro announced in March 2018 that it plans to pursue negotiations for EPAs with five SOP and Micro-SOP projects being developed by First Nations. The projects, listed below, were selected because they are part of existing impact benefit agreements with BC Hydro and/or mature projects that have significant First Nations involvement.

- Tsilhqot'in Solar – a one megawatt solar power project led by Tsilhqot'in National Government near Hanceville.
- Siwash Creek– a 500 kilowatt hydroelectric project in partnership with Kanaka Bar Indian Band near Boston Bar.
- Sarita River – a five megawatt hydroelectric project led by Huu-ay-aht First Nation near Bamfield.
- Sukunka Wind – a 15 megawatt wind power project led by Saulteau First Nations near Chetwynd.
- Zonnebeke Wind – a 15 megawatt wind power project with West Moberly First Nations near Chetwynd.

BC Hydro Aquired IPP Generation Output by Resource Type



Source: BC Hydro

*Energy Recovery, Municipal Solid Waste, and Solar

EPA Renewals

In May 2018 BC Hydro applied for BCUC approval of renewed EPAs entered into in respect of three hydroelectric projects –Sechelt Creek Hydro, Brown Lake Hydro and Walden North Hydro – whose original EPAs date back to the early to mid-1990s.

The renewal EPAs have been modelled on the more robust present-day EPA forms, and include changes to the following key terms, all to the benefit of BC Hydro: energy price escalation; environmental attributes; First Nations consultation; revenue metering; dispatch/turn-down rights; exclusivity; and termination rights. In its publicly-filed application, BC Hydro redacted key EPA provisions, including renewal term and energy pricing. In response to BCUC comments, BC Hydro subsequently disclosed the term of the renewal EPAs as being 40 years.

Although renewal EPA pricing provisions have not been disclosed on the basis of commercial sensitivity, BC Hydro's application to the BCUC notes that the levelized energy prices for the renewal EPAs are lower than under the original EPAs' evergreen provision. This is consistent with BC Hydro's stated intention to negotiate EPA renewals on the basis of, among other things, the opportunity cost of the project developer, the electricity spot price, and the cost of service for the developer, including an acceptable rate of return given the risk borne by it.

In seeking BCUC approval for the EPA renewals, BC Hydro also noted unique benefits associated with the three projects, including:

- the proximity of the Sechelt Creek project to BC Hydro's load centre, and the fact that the project delivers a relatively high proportion of its annual energy during BC Hydro's peak load months;
- the storage benefits provided by the Brown Lake project, which can provide standby resources in case of a forced or planned outage for BC Hydro's transmission line; and
- the Walden North project's continued diversion of water into Seton Lake, which allows for additional BC Hydro generation at its Seton Generating Station while being supportive of fish spawning in the related Bridge River system.

In October 2018, BC Hydro sought and obtained BCUC approval to suspend the regulatory timetable for the EPA renewal applications until four weeks following the release by the government of the BC Hydro Review.

Earlier in 2018, BC Hydro had separately sought BCUC approval for short-term extensions and amendments to existing EPAs for the Armstrong and Williams Lake biomass projects. These extensions are intended to extend those EPAs until the anticipated completion of BC Hydro's longer term energy strategy for biomass facilities. As in the case of the renewals described above, these applications have been suspended pending the broader BC Hydro Review.

BC Hydro has stated that it plans to acquire through renewed EPAs 50% of the energy and capacity contributions of existing bioenergy EPAs and 75% of the contributions of the existing run-of-river hydroelectric EPAs that are due to expire by 2024.

LNG Update

LNG Canada will proceed to construct a $40 billion LNG facility in Kitimat, British Columbia

Following years of planning and speculation around BC's nascent LNG industry, the first large-scale LNG project announced its final investment decision ("FID") in October 2018. LNG Canada – a joint venture between Shell, PETRONAS, PetroChina, Mitsubishi Corporation and KOGAS – will proceed to construct a $40 billion LNG facility in Kitimat, British Columbia. Initially, two LNG units will provide approximately 13 million tonnes per year of LNG for export, eventually increasing the production to 26 million tonnes. Additional project details include:

- each joint venture participant will be responsible to provide its own natural gas supply and will individually offtake and market its share of LNG;
- TransCanada Corporation will build, own and operate the 670 km Coastal GasLink ("CGL") pipeline that will connect natural gas from northeastern British Columbia to the export plant in Kitimat;
- the joint venture of JGC-Fluor Corporation will be the engineering, procurement and construction contractor for LNG Canada and will construct the project on a lump sum basis; and
- the LNG plant and CGL pipeline will together employ approximately 10,000 people at peak construction with up to 900 people at the plant during the operations of the first phase.

Pursuant to an electricity supply agreement entered into with BC Hydro in 2014, the LNG Canada project is expected to draw approximately 2,000 GWh per year of electricity from BC Hydro's grid to power its ancillary (non-liquefaction) activities. With LNG Canada targeting a 2024 completion date, this new load is expected to coincide with Site C's targeted in-service date.

In addition, Woodfibre LNG announced a positive FID in November 2018, and continues to achieve milestones in the development of its small LNG project near Squamish, British Columbia, including entry into a preliminary offtake agreement with CNOOC Gas and Power Group, China's largest LNG importer, and completion of impact benefit arrangements with the Squamish Nation. The $1.6 billion project is expected to produce 2.1 million tonnes of LNG per year for export by 2023-2025, and is set to commence construction in the first quarter of 2019.

There remain 13 LNG export proposals in BC at various stages of development, following the announcement on December 20, 2018 by Exxon Mobil and Imperial Oil that they are withdrawing from the BC environmental assessment process their proposed $25 billion WCC LNG Project located near Prince Rupert, British Columbia. In March 2018, Woodside Energy announced it is no longer pursuing development of the Grassy Point LNG project, instead choosing to focus on the Kitimat LNG project, a joint venture with Chevron, as part of its long-term development strategy in Canada.

What to Expect In 2019

BC HYDRO REVIEW

As noted above, the BC government's report on the first phase of the BC Hydro Review is expected to be released in early 2019. In the second phase of the review, the government will establish an expert panel to provide recommendations to ensure BC Hydro is well positioned to maximize opportunities flowing from shifts taking place in the global and regional energy sectors, technological changes, and climate action.

The second phase of the review will be informed by new government strategies including an energy roadmap for the future of BC energy and the province's CleanBC climate strategy. Terms of reference for this second phase, including the make-up of the expert panel, will be finalized after the first phase of the review has been completed. It is anticipated that the panel would deliver its recommendations to government by summer/fall of 2019.

INTEGRATED RESOURCE PLAN

BC Hydro is overdue in updating its Integrated Resource Plan ("IRP") – the long-term plan to meet the province's future electricity demand through conservation, generation and transmission, and through upgrades to existing infrastructure. Last prepared in 2013, the IRP has been delayed in order to take into account the BC Hydro Review and the province's emerging energy roadmap, and is expected to be released later in 2019.

BCUC – BACK IN ACTION?

As the government grapples with the twin imperatives of maintaining affordable rates while addressing BC Hydro's deferral accounts, a key component of the BC Hydro Review will be addressing the future role of the BCUC in rate-setting and other energy regulatory matters. To date, both the Auditor General and the government have been critical of the prior government's repeated interference with the BCUC. While this may suggest a potential return to a more independent regulator, the government will be weighing the potential risks that this poses to their stated commitment to maintaining affordable rates.

LNG – MORE TO COME?

LNG proposals in BC will continue to face uncertainty in 2019 given turbulence in global energy markets and trade relations. Of the proposals remaining, the most anticipated is the Kitimat LNG project, a joint venture between Chevron and Woodside Energy, which has lagged the LNG Canada project by approximately 1-2 years and would likely time any FID to avoid competing with LNG Canada for the limited labour force in the Kitimat area.

EPA RENEWALS

As we noted last year, fourteen of BC Hydro's EPAs with independent power producers will expire by the end of 2019. As discussed above, BCUC approval of proposed renewal or extension EPAs for five projects has been suspended pending the completion of the BC Hydro Review – watch for a decision on these later in 2019 and additional applications by BC Hydro in respect of other expiring EPAs.

Alberta Regional Overview

Authors: Kerri Howard, Kimberly Howard, and Amelia Martin

Introduction

Alberta's electricity industry continues to be in a state of transition. The main policy drivers for the electricity market transition originate in Alberta's Climate Leadership Plan and include: (i) Alberta's implementation of the Climate Plan originally announced in November of 2015; (ii) market restructuring from a fully deregulated energy-only regime to a hybrid market incorporating capacity payment mechanisms; and (iii) the phasing-out of emissions from coal-fired generation by 2030.

Key developments in 2018

IMPLEMENTATION OF CAPACITY MARKET

On June 11, 2018, *Bill 13: An Act to Secure Alberta's Electricity Future* was passed, providing the legal framework to support Alberta's transition to a capacity market. Bill 13 is intended to enable the establishment of the capacity market, clarify duties and responsibilities of the Alberta Electric System Operator ("AESO"), the Alberta Utilities Commission ("AUC"), and the Market Surveillance Administrator ("MSA") in the operation of the capacity market, increase oversight of the AESO's rule-making process, and enhance stakeholder participation in rule development. Under Bill 13, the AESO is tasked with operating and managing the capacity market including the development of rules regarding capacity auctions, capacity market participants, and capacity payments. The AESO is now required to consult with market participants, stakeholders, and the MSA when it develops Independent System Operator ("ISO") rules and must establish a process for stakeholders to propose changes to such rules. Further, all new rules developed by the AESO must now be reviewed and approved by the AUC.

In light of Bill 13, the AUC introduced Rule 017: *Procedures and Process for Development of ISO Rules and Filing of ISO Rules with AUC*, effective August 1, 2018. Rule 017 requires the AESO to demonstrate it engaged in stakeholder consultation prior to submitting a rule for AUC approval. Further, when the AESO submits any rules related to the capacity market, it must identify how long the rule will be in effect, how the rule will affect the performance of the capacity market and electricity market, and how the rule supports ensuring a reliable supply of electricity at a reasonable cost to customers.

Given its direction under Bill 13, the AESO released its Comprehensive Market Design proposal ("CMD Final") for Alberta's capacity market on June 29, 2018. The CMD Final forms the foundation for the development of new ISO rules and the amendment of existing ISO rules. Topics covered in the CMD Final include the determination of resource capacity value, determination of a procurement demand curve, auction mechanics, market power mitigation measures, and integration with existing energy and ancillary services markets.

The AESO released Set 1, Set 2, and Set 3 of its proposed new ISO rules for the capacity market in August 2018. Set 1 and Set 2 deal with capacity market rules while Set 3 addresses demand curve rules. Consultation sessions on the new rules were held in August and September 2018 and stakeholder comments were solicited for all three sets of rules. The AESO has also posted draft information documents on the proposed rules to help stakeholders better understand the rules. The AESO expects to submit the new ISO rules to the AUC for approval in the first quarter of 2019.

The first capacity procurement is set to begin in late 2019 and it is anticipated that the capacity market will be operational in 2021. Once operational, Alberta's electricity market will be comprised of three separate markets: (i) the existing market for energy, (ii) the existing market for ancillary services, and (iii) a new market for capacity in which generators will agree to have the availability to supply electricity when required.

AESO'S RENEWABLE ELECTRICITY PROGRAM

In 2017, Alberta's Renewable Electricity Act came into force, providing powers to the AESO to administer a competitive bid process for its Renewable Electricity Program ("REP"). Under the REP, successful bidders enter into a Renewable Electricity Support Agreement ("RESA") with the AESO, which will provide a 20-year indexed renewable energy credit, structured akin to a contract for difference, to cover any difference between the participant's bid price for energy generated from a project and the pool price of energy in the market. The REP was discussed in detail in our 2017 Canadian Power industry retrospective.

Round 2 (REP 2) and Round 3 (REP 3) of the REP were announced on February 5, 2018 and closed on October 24, 2018. The successful projects were announced on December 17, 2018 and have a weighted average price of 3.9 cents per kilowatt hour (kWh), slightly above the record-low price of 3.7 cents per kWh set in Round 1 of the REP.

The three successful REP 2 projects include a minimum of 25% Indigenous equity ownership, as required by the round two Request for Proposals, and will have an installed capacity of 360 megawatts of renewable energy, enough to power close to 150,000 homes at a weighted average rate of 3.8 cents per kilowatt-hour.

The successful REP 3 projects are expected to have an installed capacity of 400 megawatts of renewable energy, powering close to 170,000 homes at a rate of 4.0 cents per kilowatt-hour.

All five projects are expected to begin construction in 2020 and be operating by mid-2021.

ALBERTA UTILITIES COMMISSION LAUNCHES ELECTRIC DISTRIBUTION SYSTEM INQUIRY

In December 2018, the AUC announced it was launching an inquiry into the changing electric distribution system in Alberta. The AUC's inquiry will focus on answering three key questions:

- How will technology affect the grid and incumbent electric distribution utilities and how quickly?

– Where alternative approaches to providing electrical service develop, how will the incumbent electric distribution utilities be expected to respond and what services should be subject to regulation?

– How should the rate structures of the distribution utilities be modified to ensure that price signals encourage electric distribution utilities, consumers, producers and alternative technology providers to use the grid and related resources in an efficient and cost effective way?

Stakeholder comments were submitted in January 2019 and results of the inquiry are expected later in the year.

NEW AND CONTINUING RENEWABLE ENERGY PROGRAMS

Solar-Generated Electricity Request for Proposals

In October 2018, Alberta Infrastructure issued a Request for Proposals ("RFP") for the procurement of 135,000 MWh solar-generated electricity each year for the next 20 years. Before releasing the RFP, Alberta Infrastructure sought input from industry stakeholders through a Request for Information in August 2018. Successful bid participants and Alberta Infrastructure will enter into Solar Electricity Support Agreements similar to the AESO's RESAs. Contracts are expected to be in place by the spring of 2019.

Community Generation Program

On November 22, 2018, the Government of Alberta announced the new Community Generation Program – a partnership between Energy Efficiency Alberta and the Municipal Climate Change Action Centre – to support the installation of locally generated renewable energy projects. The Government of Alberta is investing $200 million over 20 years for the Program with up to $50 million of the investment going towards projects in communities affected by the phase-out of coal-fired electricity.

Expected to launch in the fall of 2019, open houses will be held and an online resource hub will be developed to help communities prepare to participate in the Program. Qualifying projects are expected to demonstrate social, economic or environmental benefits to the community, such as training opportunities or the development of community infrastructure. Eligible groups will include societies and non-profit organizations, condo corporations, educational institutions, first nations and Métis settlements, and municipalities. Projects will be structured akin to a contract for difference to cover any difference between the participant's bid price for the energy generated from a project and the pool price of energy in the market.

The implementation of the Program is made possible by the Small Scale Generation Regulation, which comes into force on January 1, 2019. This new regulation provides rules to enable small-scale and community renewable energy projects to supply electric energy to the grid and is intended to reduce regulatory and financial barriers for small scale generators.

Indigenous Climate Leadership Programs

In support of its Indigenous Climate Leadership Initiative, the Government of Alberta provided grants to Indigenous communities under the following programs in 2018:

- Alberta Indigenous Solar Program: Provides grants of up to $200,000 for Alberta Indigenous communities or organizations to install solar power systems.
- Alberta Indigenous Community Energy Program: Enables Indigenous communities and organizations to apply for grants up to $200,000 to conduct detailed energy assessments of community-owned buildings to help identify energy conservation opportunities.
- Alberta Indigenous Green Energy Development Program: Supports Indigenous community-owned renewable energy generation projects with a generation capacity above 1 MW. There are two separate funding streams under the program – one for project development and one for project implementation. All forms of renewable energy generation that support the reduction of greenhouse gas emissions are eligible and there is no funding cap.
- Alberta Indigenous Climate Planning Program: Supports Indigenous communities in establishing an understanding of their current and future energy needs and in pursuing opportunities related to renewable energy and participating in the green economy. Applicants can apply for funding up to $100,000.
- Alberta Indigenous Energy Efficiency (Retrofit) Program: Provides funding to Indigenous communities and organizations to improve energy efficiency and reduce greenhouse gas emissions of Indigenous-owned existing or new buildings.

Custom Energy Solutions

Energy Efficiency Alberta, in partnership with the federal government, announced the launch of the Custom Energy Solutions program in May 2018. This new three-year program provides funding for industrial and commercial operators to conduct assessments of their facilities' energy use and to develop a plan to identify the most cost-effective energy upgrades. Operators that move forward with energy efficient upgrades will have up to 50% of the capital cost of the upgrades funded by the program. Up to $1 million per year is available for single facilities and up to $2 million for operators making upgrades to multiple facilities.

Changes to Residential and Commercial Solar Program

Energy Efficiency Alberta announced increases to the incentive levels under its Residential and Commercial Solar Program in November 2018. Any eligible commercial, institutional, or non-profit participant that installs a solar system will be eligible for an incentive of up to $1,000,000 or 35% of solar system costs (whichever is less). This is an increase from the previous cap of $500,000.

Property Assessed Clean Energy ("PACE") Program

On June 11, 2018, the Government of Alberta passed An Act to Enable Clean Energy Improvements, which will enable municipalities to establish PACE programs to make it more affordable for commercial, agricultural and residential property owners to make clean energy improvements such as installing solar panels or high-efficiency heating and cooling systems. Interested property owners will sign an agreement with the municipality to pay back the cost of the improvement through their property taxes. The legislation is expected to come into force in 2019 after stakeholder consultation is complete.

MARKET RULE DEVELOPMENTS

New ISO Rules and Amendments

Following announcement of the Renewable Energy Program, the AESO conducted a series of consultations for the AUC in respect of the ISO rules. The result of the consultation process was a set of amendments collectively known as the "Wind, Solar, AGF and DER Rule Amendments and Definition Amendments" (the "Amendments"), which were released in 2017, but did not come into effect until September 1, 2018.

Highlights of the Amendments to the ISO rules include:

- Substantive changes to Section 304.3 (Wind and Solar Power Ramp Up Management) relating to the procedures surrounding power limit pro rata shares and the interaction between the market merit order provisions of the rules and pro rata shares.
- The addition of Section 304.9 (Wind and Solar Aggregated Generating Facility Forecasting) as a new section of the rules addressing the forecasting requirements for an aggregated generating facility.
- Substantive changes to Section 502.1 (Aggregated Generating Facilities Technical Requirements) and Section 502.8 (SCADA Technical and Operating Requirements) relating to specific operating requirements of aggregated generating facilities and synchronous generating units.
- The addition of Section 502.16 (Aggregated Generating Facilities Operating Requirements) as a new section to the rules addressing the key requirements to operate and maintain an aggregated generating facility.

Specified Penalties for Contravention of AUC Rules

New AUC Rule 032: Specified Penalties for Contravention of AUC Rules came into effect on January 1, 2019. The new rule allows the AUC to issue a notice of specified penalty under section 63.1(1) of the Alberta Utilities Commission Act if the AUC is satisfied a party has broken one or more of the rules specified in the Penalty Table included in Rule 032. Notices of specified penalties will be posted on the AUC's website on the date they are issued, including whether or not the penalty has been paid or is being disputed. Penalties range from $500 for a first offence to $10,000 for a 21st offence. Rule 032 gives the AUC two years from the date it first knew or ought to have known about a contravention to issue a notice of specified penalty, or four years after the date of the contravention, whichever expires first.

Offer Behaviour Guidelines Prior to the Implementation of a Capacity Market

In 2011, the Alberta Market Surveillance Administrator ("MSA") issued Offer Behaviour and Enforcement Guidelines ("OBEG") to provide guidance on how the MSA would interpret the requirements of the Fair, Efficient and Open Competition Regulation ("FEOC Regulation").

A central feature of the OBEG was to address the unilateral exercise of market power by generators who were economically withholding energy. The MSA stated that the exercise of market power was not inconsistent with the FEOC Regulation. Unless the exercise of market power sought to restrict a competitive response from competitors or customers, a breach of AESO rules or providing misleading records, the MSA's approach was to not pursue enforcement remedies for unilateral exercises of market power. The MSA's rationale for this position was that, even though the exercise of market power could lead to static inefficiency (i.e., prices that do not reflect marginal costs), such a loss of efficiency could be offset by dynamic efficiency and investment and innovation.

In 2017, with the proposed arrival of a capacity market organized by the AESO, the MSA concluded that the proposed capacity market (not the energy market) will incent new generation. The MSA thus stated that "certain market participant conduct that results in static efficiency losses would now not result in dynamic efficiency gains from innovation and investment." The MSA withdrew the OBEG and provided no guidance on how the MSA would treat offer behaviour other than to state that the MSA would review whether generator conduct had a deleterious effect on market outcomes." The MSA did not specify what a "deleterious effect on market outcomes" would be.

On September 27, 2018, the MSA issued notice that it had retained an independent consultant to assess whether offer behaviour guidelines were needed during the period prior to the implementation of a capacity market. The consultant's report, released on December 10, 2018, did not recommend the implementation of new offer behaviour guidelines on the basis that there is little cause for concern about higher than competitive prices occurring during the transition period. Further, the report found the development and implementation of technically sound guidelines would be challenging given the relatively short transition period. The MSA will make a final decision on this matter after receiving stakeholder comments on the report.

GOVERNMENT MANDATED CUTS TO OIL PRODUCTION

On December 4, 2018, the Government of Alberta announced temporary measures to reduce the production of raw crude oil and bitumen by 325,000 barrels per day (an 8.7% reduction) in an attempt to improve the value of Alberta oil and decrease the amount of oil in storage. The Alberta Energy Regulator will implement the reductions commencing January 2019. The first 10,000 barrels produced by each operator will be exempt. Monthly reviews will be conducted to assess how production is balancing with export capacity and reductions are expected to decrease as the storage glut is drawn down. The government's authority to reduce production ends on December 31, 2019. The economic downturn in Alberta and reductions in oil and gas production in Alberta could have a ripple effect on electricity demand throughout the province.

The economic downturn in Alberta and reductions in oil and gas production in Alberta could have a ripple effect on electricity demand throughout the province.

What to expect in 2019

With an election looming in May 2019, uncertainty lies ahead in Alberta. Alberta's current government, led by the New Democratic Party ("NDP") and Premier Rachel Notley, introduced numerous initiatives to develop more renewable energy projects through its Climate Leadership Plan. If re-elected, renewable energy operators could expect the NDP to continue many of these new initiatives to encourage development of the renewable energy sector in Alberta. The NDP's Climate Leadership Plan included a goal of phasing out coal-fired electricity generation by 2030 and it is expected that this goal would remain in place upon re-election. As a result of the Trans Mountain pipeline expansion being halted in August 2018, the NDP government has taken a stronger stance against the federal government's climate change plan, deciding to no longer increase Alberta's carbon levy to $40 by 2021 and delaying its plan to cap oil sands carbon emissions. The growing tension between Alberta and the federal government presents further uncertainty for 2019 as it is unknown whether the federal government will decide to impose unilateral changes on provinces that refuse to participate in its climate change plan.

The United Conservative Party ("UCP"), led by Jason Kenney, is campaigning on a promise to repeal Alberta's carbon levy, stop the legislated shutdown of coal power in Alberta, and fight the federal government's carbon price plan. If elected, the UCP's plans could significantly alter the NDP's Climate Leadership Plan and likely impact the renewable energy programs that have been created under the Plan. The UCP has yet to provide a direct policy position on renewable energy adding further uncertainty to how 2019 will unfold for renewable energy operators in Alberta.

Ontario Regional Overview

Authors: Seán C. O'Neill, George Vegh, Zachary Masoud, and Taha Qureshi

Introduction

For Ontario's power sector, 2018 was marked by uncertainty and anticipation on a variety of fronts, particularly as a result of adjustment to a newly-elected provincial government that quickly implemented its markedly different policies with respect to renewable energy and climate change. Additionally, progressive change continued through initiatives such as the ongoing plan to reshape energy governance through changes to the Ontario Energy Board (the "OEB").

Political Change – Keeping Ontario Interesting

In June 2018, the Progressive Conservative Party of Ontario came into power after fifteen years of governance by the Ontario Liberal Party. The change in government has led to some uncertainty and anticipation for Ontario's power sector in 2018 and beyond as during the election campaign the Conservatives had signalled significant departures from the Liberals' renewable energy and climate change programs. On July 13, 2018, new Minister of Energy, Northern Development and Mines, Greg Rickford, issued a Minister's Directive (the "Directive") directing the Independent Electricity System Operator ("IESO") to immediately take all steps necessary to: (i) wind down all feed-in tariff ("FIT") 2, 3, 4 and 5 contracts where the IESO had not already issued a notice to proceed ("NTP") in respect of the project, and (ii) wind down all Large Renewable Procurement I ("LRP I") contracts where the IESO had not already notified the proponent that all of its project's key development milestones had been met. Minister Rickford also announced that the new government would cancel and wind down 758 renewable energy contracts (mostly comprised of FIT and LRP I contracts), stating that this decision would result in Ontario ratepayers benefitting from $790 million in savings "even after all costs are accounted for". As justification for this change, the Directive stated that the IESO's recent system planning work "indicates that Ontario's current contracted and rate regulated electricity resources are sufficient to satisfy or exceed forecasted provincial needs for the near term and that there are other means of meeting future energy supply and capacity needs at materially lower costs than long-term contracts that lock in the prices paid for these resources."

Relating to the cancellation and winding down of these 758 renewable energy projects, the Ministry of the Environment and Climate Change is currently consulting on a proposed regulatory amendment to the *Renewable Energy Approvals Regulation* (Ontario Regulation 359/09). This proposed change would require anyone planning a renewable energy project to demonstrate a demand for the electricity created by such proposed energy project in order to be eligible for a renewable energy approval. The Ontario government has indicated that this proposed amendment is "consistent with [the] government's decision to wind down long-term contracts for electricity that the system does not need at this time".

Ontario's new Conservative government also passed the *Urgent Priorities Act, 2018* (the "Act"), which received Royal Assent on July 25, 2018. The Act targeted the White Pines Wind Project, an 18.45 MW on-shore wind project that received its NTP from the IESO on May 11, 2018 and effectively terminated its FIT contract. A more detailed discussion of the White Pines Project can be found in our article on sovereign risk, which can be located on page 26 of this publication.

Repeal of the Green Energy Act

To complete the dismantling of existing renewable energy programs, on December 6, 2018, the Ontario government passed the *Green Energy Repeal Act*, 2018 (the "GERA") to repeal the *Green Energy Act, 2009* (the "GEA") and certain associated regulations. The GEA had introduced laws that were billed as simplifying and streamlining renewable energy project development but the legislation also created rancor, particularly among local governments and residents concerned about project proliferation. The GERA (i) re-enacts certain provisions of the GEA relating to conservation and energy efficiency initiatives, (ii) amends the *Planning Act, 1990* to increase the power of municipalities to reject renewable energy projects and (iii) amends the *Environmental Protection Act, 1990* to provide authority to the Lieutenant Governor in Council to make regulations prohibiting issuance or renewal of renewable energy approvals, including where demand for electricity created by such energy project is not demonstrated.

Notwithstanding its apocalyptic title, the GERA did not completely undo the GEA, as certain provisions of the GEA have been re-enacted as part of the *Electricity Act, 1998*. The re-enacted provisions permit the government to create regulations in certain areas, including (i) energy and water efficiency standards for appliances and products in Ontario, (ii) permitting the use of certain goods, services and technologies notwithstanding restrictions that may otherwise prevent their use (such as outdoor clotheslines in a residential context even if a condo corporation prohibits their use), (iii) requiring certain building owners to report their building's energy and water consumption and greenhouse gas emission data annually, and (iv) requiring annual reporting by municipalities, municipal service boards, universities, colleges, schools and hospitals on their energy use and greenhouse gas emissions and the publishing of such reports on their websites.

Ontario Plan to Combat Climate Change

On November 29, 2018, the Ontario government introduced its plan to combat climate change through the "Preserving and Protecting our Environment for Future Generations: A Made-In-Ontario Environment Plan" (the "Plan"). The Plan purports to recognize the importance of tackling rising emissions levels globally in order to limit the impact and damage of climate change. It also recognizes the growing role of clean tech industries in the Ontario economy and aims to encourage investment in the clean tech sector as a major policy tool for tackling climate change. A major feature of the Plan is to align Ontario's emissions reduction targets with Canada's obligations under the Paris Agreement to achieve a 30% reduction of emissions levels (relative to 2005 levels) by 2030. To achieve the portion of the reduction target unfulfilled to date, the Plan replaces the cap-and-trade program introduced by the previous Liberal government with a host of new policy initiatives aimed at engaging and promoting collaboration between the public and the private sectors.

Among the high-level policy initiatives outlined by the Plan are new emissions performance standards to be imposed on large industrial emitters, facilities and operators in correlation with their level of output or production. While the Plan provides scant details, there are indications that it could follow in some part Saskatchewan's plans to implement a similar output-based mechanism. Saskatchewan's emissions plan provides alternatives to polluters who do not meet the province's emissions standards such as purchasing off-set or performance credits.

The Plan also: (i) envisions the establishment of a $400 million public fund to leverage up to $1 billion in private sector funds for investment in clean technology on a commercially viable scale, (ii) contemplates a $50 million reverse auction scheme through which the provincial government will issue requests for proposals for the development of emissions reduction projects and bidders will bid for such contracts or services with the bidder with the lowest cost per tonne of emissions being selected, and (iii) commits to finding advanced technological solutions for reducing litter and waste, protecting the province's waterways and managing the remediation of contaminated soil.

The provincial government is soliciting further feedback and input on the Plan from the public until the end of January 2019.

A discussion of other environmental law developments across Ontario with potential impacts on the energy sector can be found in our article on environmental law, which can be located on page 29 of this publication.

Reshaping Energy Governance – OEB Reform

In December 2017, the previous Ontario government launched a year-long review of the OEB to consider the appropriate mandate, role and structure of a modern energy regulator. The OEB Modernization Review Panel (the "Panel") was constituted to engage with the public and procure expert input and feedback, with the goal of producing a final report with recommendations for the Ministry of Energy on a range of issues, including disruption and innovation, governance framework and stakeholder relationships. In connection with such ongoing matters, the OEB introduced its draft local distribution company ("LDC") governance framework for consultation, which is raising discussion in industry about the practicality of implementation by smaller LDCs and the authority of the OEB to implement such recommendations.

The new government reduced the Panel's mandate to focus on the OEB's structure and governance. The Panel presented its report to Minister Rickford in 2018 and the Minister is expected to include those recommendations in his consideration of a number of OEB-related reforms, which may include the potential restructuring of the OEB into administrative and adjudicative arms (along the lines proposed for the National Energy Board in Bill C-69).

Another committee – the OEB's Advisory Committee on Innovation – issued its report to the OEB in November 2018. Its recommendations addressed how the OEB may facilitate innovation in technologies and business models in the regulated energy sector. Changes were proposed in relation to utility remuneration, provision of competitive services and the integration of distributed energy resources. The OEB will commence consultations on the report in January 2019.

Québec Regional Overview

Authors: Louis-Nicolas Boulanger, Mathieu LeBlanc, Matthieu Rheault, and Martin Thiboutot

Introduction

In Québec, 2018 was another year that did not provide any indication or hope of any new significant procurement of renewable energy from independent power producers in the near future, which is viewed by many political observers as being too costly in the current Québec environment.

It will be interesting to see the impact that the election, on October 1, 2018, of the *Coalition Avenir Québec* ("CAQ") government will have on the Québec energy sector. To contribute to the fight against climate change, the CAQ government has prioritized the increase of the province's clean energy exports in order to help neighbouring provinces and states replace energy produced by gas, coal or nuclear facilities. In the meantime, at the end of November, not long after the election, Premier François Legault stalled the development of the Apuiat wind farm project by announcing that it would not move forward as long as Hydro-Québec has an energy surplus.

Meanwhile, Hydro-Québec has continued to focus on developing new markets, such as exports to northeastern U.S. states, with a view to increasing profitability and restraining the rise of electricity rates for Québec consumers. In November 2018, the Supreme Court of Canada issued a long-awaited decision that put an end to the longstanding Churchill Falls dispute between Québec and Labrador by ruling in favour of Hydro-Québec. Other noteworthy developments in 2018 include increasing demand for new electricity supplies for blockchain technology uses and the announcement of the selected proponent to build a six megawatt wind farm in the Îles-de-la-Madeleine, which is meant to reduce Hydro-Québec's use of its Cap-aux-Meules oil-fired thermal plant and resulting greenhouse gas emissions.

Election

Undoubtedly, the election of the CAQ government was one of the noteworthy developments in the Province of Québec in 2018. For the first time in more than 50 years, a party other than the Liberal Party or the *Parti Québécois* is governing the Province of Québec.

Energy policy was not a central piece of the campaign platform of any political party running for election. However, based on declarations from various members of the CAQ government prior to its election, the province should not be seeking new electricity procurement as long as Hydro-Québec is experiencing substantial surpluses.

Since being elected, however, Premier Legault has outlined a few key elements of his government's energy strategy which include using Québec clean energy to convince certain industries to set up shop in the province, and accelerating the conversion of the transport industry to electricity, including important investments in the public transport sector.

In line with a statement to make Québec the "battery" of North America using clean energy generated in the province, Premier Legault has also raised the possibility of entering into a privileged relationship with Ontario in order to replace some of Ontario's nuclear capacity (which requires significant refurbishment investments) by providing electricity from Québec's hydroelectric facilities. This initiative would facilitate the desire of the provincial government to increase efforts to eliminate Hydro-Québec's electricity surpluses.

But it is the fate of the Apuiat wind energy project which grabbed the energy headlines since the election of the CAQ Government. The 200 megawatt Apuiat project, first proposed in 2015, was located in the Côte-Nord region, near the town of Port-Cartier, and was being developed by a Québec-based independent power producer, in partnership with Innu communities. Hydro-Québec was expected to purchase the electricity from the project.

Shortly after its October election, Premier Legault announced that the project would not move forward, citing Hydro-Québec arguments that it would cost billions of dollars to taxpayers over the life of the project.

U.S. Exports

In January 2018, Massachusetts utilities announced the selection of Hydro-Québec's Northern Pass project, a 192-mile electric transmission line project that would bring 1,090 megawatts of clean hydropower to Massachusetts. This project was developed by Hydro-Québec along with its U.S. based partner Eversource Energy and was submitted in response to a request for proposals launched in March 2017.

The Northern Pass project was said to be Hydro-Québec's most important contract since it began developing its export markets and the export contract associated with this project is expected to generate up to $500 million in annual revenues for Hydro-Québec.

However, the Northern Pass project was blocked just days after this announcement when New Hampshire's Site Evaluation Committee denied an application for a permit to build the project over concerns it would negatively impact tourism and property values. The proponent has appealed this decision and, on October 12, 2018, the New Hampshire Supreme Court has agreed to hear the appeal. The case is expected to be heard in early 2019.

Hydro-Québec has also been working on alternative projects to export electricity into the U.S. These projects include the New England Clean Energy Connect, with Central Maine Power, which would connect Québec's network to Maine, and the New England Clean Power Link, which would allow Hydro-Québec to transport power in New England through Vermont. However, none of these projects are as advanced as the Northern Pass project.

End of Churchill Falls Dispute

On November 2, 2018, the Supreme Court of Canada put an end to a longstanding legal dispute between Hydro-Québec and Churchill Falls (Labrador) Corp ("Churchill Falls"). The court sided with Hydro-Québec, ruling that the Québec utility had no obligation under Québec civil law to renegotiate the 65-year contract signed in 1969 under which Hydro-Québec agreed to buy Churchill Falls power at a fixed rate that was set to decrease over time.

Churchill Falls had argued that the contract ought to be renegotiated, on the basis that the energy market has changed dramatically in an unforeseeable manner since the contract was first signed. The Supreme Court refused to force the renegotiation of the contract, stating that the doctrine of unforeseeability was not part of Québec civil law as the Québec legislature had refused to incorporate this doctrine in the province's legislation.

Since the execution of the contract, Hydro-Québec's mandate has evolved and the utility has made billions of dollars exporting to previously non-existent markets at 20 to 40 times the contract price. As a result, the contract has delivered substantial profits to Québec and relatively modest benefits to Newfoundland and Labrador. The contract, which is set to expire in 2041, has yielded nearly $28 billion in profits to Québec, compared to just $2 billion for Newfoundland and Labrador.

Blockchain and Other Technology Uses

2018 saw the first reaction of the Québec government and Hydro-Québec, the province's almost exclusive electricity distributor, to the increasing demand for new electricity supplies for blockchain technology uses after receiving nearly 300 demands of that type for an aggregate of 18,000 megawatts of new capacity. The volume of demands made it nearly impossible to manage on a "first come, first served" basis (as is usually the case) and threatened to compromise the reliability and safety of Hydro-Québec's system and supplies.

In June 2018, Hydro-Québec applied to the Régie de l'énergie, Québec's energy market regulation board, for an authorization to suspend the processing of demands made by blockchain technology users and the adoption of a new dissuasive electricity rate of 15 cents per kilowatt hour for that category of customers already serviced by Hydro-Québec, until complete terms of service are approved for a new electricity bloc of 500 megawatts intended for this specific use. Hydro-Québec's request was initially authorized by the Régie de l'énergie and a ruling with respect to the terms of service for the new 500 megawatts electricity bloc is expected in the next few months. Based on the instructions given by the Québec government in a May 2018 decree, the new 500 megawatts electricity bloc will be intended for customers operating computer equipment dedicated to calculations which serve to validate successive transactions made by users of a blockchain, with a supply demand in excess of 50 kilowatts. The bloc and the selection process will aim to maximize benefits for Québec in terms of electricity sales, tax revenues, investments and job creation.

It will be interesting to see, in the next few months, how blockchain industry participants will react to this major development in an energy market which, until recently, could offer them attractive energy costs. In 2019, these participants may continue showing great interest in hydro and other generating facilities in the province which are without an offtake agreement or nearing the end of their useful life.

Selected Proponent for Hydro-Québec's 6 MW Wind RFP in Îles-de-la-Madeleine

On March 9, 2018, Hydro-Québec Distribution ("HQD") announced that Valeco Énergie Québec inc. was the selected proponent for the development, construction and operation of a six megawatt wind project in the Îles-de-la-Madeleine, Québec. A total of three submissions from TUGLIQ Energy, Kruger Energy and Valeco Énergie Québec were received by HQD for a wind power project with guaranteed commencement dates of delivery between October 1 and December 31, 2019.

The objective of this project is to integrate a wind project into the off-grid system of the Îles-de-la-Madeleine, which would contribute to reducing Hydro-Québec's use of its Cap-aux-Meules oil-fired thermal plant and is expected to result in a reduction of approximately 13% of the Îles-de-la-Madeleine network greenhouse gas emissions.

TOPICAL ANALYSES

Risky Business - Termination of the White Pines Wind Project and Sovereign Risk in Ontario

Authors: Christopher Zawadzki, Kerri Lui, and Seán O'Neill

It would be difficult for anyone involved in the Ontario renewable power industry to say that they were unaware of the risks posed to projects by a change in provincial government. In the 2018 provincial election campaign – as had been the case in the two previous elections – the Progressive Conservative ("PC") Party of Ontario had made it part of their platform that they would cancel renewable energy projects or contracts between the Independent Electricity System Operator (the "IESO") and project developers. However, the abruptness and bluntness of the newly-elected government's actions took most by surprise. Less than a month into office, on July 25, 2018, the new Ontario government took swift action to pass legislation to unilaterally terminate an 18.45 MW wind project in the Prince Edward County region of Ontario known as the White Pines Wind Project (the "Project"). The *White Pines Wind Project Termination Act* (the "Act") was passed as part of an omnibus package of legislation set forth in the *Urgent Priorities Act, 2018*. The Act specifically targeted the Project and the Project's developer, wpd White Pines Wind Incorporated ("White Pines"), a subsidiary of the German renewable energy developer, wpd AG, and left industry participants nervously wondering if other projects or developers could be next.

The Act comprehensively covers all bases in trying to ensure that the Project is truly dead. It expressly terminated the contracts to which the IESO had been party with White Pines, namely, a "version 1" Feed-in-Tariff contract and a secured lender consent and acknowledgement agreement, this latter contract also including the construction lenders to White Pines as a party. The Act also included further measures, including: (a) providing Cabinet the power to retroactively terminate by regulation any other contracts to which White Pines was party; (b) revoking key permits, including the critical Renewable Energy Approval, issued to White Pines; and (c) requiring White Pines to decommission the Project within one year and to remain liable to the Crown for any failure to do so. The Act was not without recompense to White Pines and its stakeholders as it did provide certain entitlements to compensation from the Crown. In the case of the Project's lenders, full repayment of debt and makewhole is provided. However, in the case of the developer, compensation was limited to costs resulting from development, employee terminations, subcontractor or landlord losses and decommissioning. Payment to the developer explicitly excluded compensation for any loss of goodwill or profits unless otherwise provided by regulation, suggesting that cooperation by the developer could be rewarded by compensation in addition to reimbursement of incurred costs.

The Act comprehensively covers all bases in trying to ensure that the Project is **truly dead.**

In the context of the 758 renewable energy contracts that the new PC government had cancelled the week before, the cancellation of one more wind project may not seem like a big deal. However, in the case of the 758 other cancelled contracts, those contracts were terminated pursuant to their early termination provisions. In the case of White Pines, the Project had previously received its Notice to Proceed ("NTP") from the IESO and there was no contractual ability of the IESO to terminate its FIT contract. Notwithstanding this inconvenient commercial fact, the Ontario government argued, as justification for the Act, that the issuance of the Project's NTP on May 11, 2018 during the election period breached the long-standing "caretaker convention" whereby governments should show restraint in exercising their authority and refrain from making unnecessary and non-routine decisions during the election periods. The Ontario government presented this rationale notwithstanding that the IESO, as a Crown corporation, operates with a great degree of independence from the legislative and executive branches of government.

Paradoxically, in attempting to redress the alleged breach of one convention, the provincial government created uncertainty around another long-standing convention, arguably one with far greater significance and possible lasting impact. Generally, the law regarding government contracts is the same as the law that applies to other contracts. If a government breaches a contract, the other contracting party may sue for damages. The assessment of damages for such a breach is subject to the same principles that apply in the case of private contracts. Notwithstanding the similarities, a key difference between government contracting and contracts between private parties arises from the fact that in Canada it is well-established that government has the power to pass laws that limit a private party's rights, including rights that such party may have just previously obtained in a contract with such government or its agency. Put another way, a government may pass clear legislation that terminates a private party's contract with such government and that denies the private party either the ability to sue or to recover damages for such termination. Governments are usually reluctant to exercise this power in contracting with private parties, however, being generally attuned to the reputational risks and chilling effect on investment that may result from its use or abuse.

The Act is a textbook example of "sovereign risk". In addition to the measures noted above taken by the Ontario government to terminate the Project, the Act bars White Pines and all other stakeholders or interested parties from making any claims, bringing any proceedings, or enforcing any judgment against the Crown, the IESO and certain related persons in connection with the termination or any provision of the Act. Germany's ambassador to Canada, Sabine Sparwasser, articulated the traditional concerns about sovereign risk in response to the Act, stating "we are trying to enhance direct investment, and in that context it is not good news if you have a case where a project by a German company that has been here for the last ten years and a project that's close to completion and that has respected all the regulation… [is] suddenly unilaterally cancelled and basically dismantled." Similarly, John Manley, President of the Business Council of Canada, in an open letter to the new Ontario government cautioned "[i]n your dealings with renewable power developers, we urge you to consider carefully the potential lasting negative effects that arbitrary actions can have on investor confidence." We expect that the Act will not quickly fade from memory of current investors and will quickly be brought to the attention of future investors in infrastructure in Ontario.

Of some comfort to other renewable energy developers, the Act did not contain a broader power to generally cancel renewable energy contracts that have achieved NTP. However, the Ontario government's willingness to unilaterally terminate the Project and its cancellation of hundreds of pre-NTP renewable power contracts has not dispelled the specter of possible future cancellations of other post-NTP contracts. Such possibility may provide the Ontario government with leverage should it decide to attempt to renegotiate the terms of such contracts, which was also a plank in the PC's campaign platform. The willingness of the Ontario government to do so may be tempered by any economic or political costs resulting from the Act. In reaction to the introduction of the Act, White Pines has claimed that cancellation of the Project will cost the Province more than $100 million, although its ability to claim or recover any such damages remains to be seen.

The previous provincial government discovered that power contract termination can result in unintended expenditures both in terms of financial and political capital. While the circumstances were different because specific legislation was never introduced, the cancellation of the 280 MW gas plant in Mississauga and the 900 MW gas plant in Oakville cost the Province approximately $1.1 billion dollars according to Ontario's Auditor General. The Act may not result in a similar, discernible price tag, and it is more likely that the effect of the Act, if any, on "sovereign risk premiums" that investors include in their decisions to deploy capital in Ontario will never be fully known.

Environmental Law

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Key developments in 2018

In 2018, there were a number of key environmental law developments across Canada with potential impacts on the energy sector. Highlights include the following:

BRITISH COLUMBIA

– **BC Proposes Changes to Provincial Environmental Assessment Regime:** In March 2018, the BC government launched the process for revitalizing the province's environmental assessment ("EA") process. On November 5, 2018, the BC government introduced *Bill 51 – Environmental Assessment Act* ("Bill 51"). If passed, Bill 51 would introduce significant changes to the provincial EA process including the creation of an early engagement process, increased opportunities for public participation, and prescriptive measures to meet the BC government's commitment to implement the United Nations Declaration on the Rights of Indigenous Peoples. The BC government is currently developing regulations to support Bill 51, which is expected to come into force in late 2019.

– **BC Releases Updated Climate Action Plan:** On December 5, 2018, the BC government released its new climate change strategy, the CleanBC plan. Pursuant to the *Climate Change Accountability Act,* the province is targeting a 40% reduction of its greenhouse gas ("GHG") emissions, representing a 27 megatonne ("Mt") cut, by the year 2030 (based on 2007 levels). Included in the CleanBC plan are rebates and tax credits aimed at stimulating the shift to clean energy, which will be announced with the provincial budget in February 2019. A key consideration in the development of the plan is the accommodation of the LNG sector in the province. The BC government estimates that the LNG Canada project in Kitimat could add up to 3.45 Mt of carbon emissions to the province's total. The CleanBC plan includes a number of emission reduction initiatives, including industry-focused initiatives such as directing a portion of BC's carbon tax paid by industry into incentives for cleaner operations and reducing methane emissions from upstream oil and gas operations by 45% by 2025 (provincial regulations are being developed by the BC Oil and Gas Commission and are expected to be passed by 2019). The CleanBC plan represents 75% of the 2030 target, with the BC government planning on rolling out the second phase of its plan to address the remaining 25% of its target over the next two years.

– **Carbon Pricing Program Changes:** Part of the CleanBC plan contemplates rolling out incentives to further reduce emissions as the carbon price rises, including a Clean Industry Fund that invests some industrial carbon tax revenue directly into emission reduction projects beginning in 2019. The plan indicates that GHG emissions information will be audited and reported annually for all large industries in BC, with GHG emission benchmarks to be established for each industry. To apply to the Clean Industry Fund, industries must provide details on their planned facility upgrades reducing GHG emissions, including a (i) detailed project plan outlining technologies or improved processes to implement and the amount of emissions they expect to reduce and (ii) business case for the project with financial details. BC's carbon tax rate will raise $5 per tonne every year, from $30 per tonne in 2018, until 2021 when it reaches $50 per tonne.

- **ZEV Mandate and BCUC Recommendation:** The BC government announced that new light-duty zero-emission vehicle ("ZEV") legislation will be introduced in spring 2019 (the "ZEV Mandate"). The ZEV Mandate will include an industry standard to be introduced in 2020 which will require all new cars and trucks sold after 2040 to be ZEVs, with a target of having 10% ZEV sales by 2025 and 30% ZEV sales by 2030. In November 2018, the British Columbia Utilities Commission ("BCUC") issued its Phase I Report on public electric vehicle ("EV") charging station inquiry. In its report, BCUC found that the BC government should issue an exemption with respect to the BCUC's regulation of EV charging services for the following reasons: (i) the public EV charging market does not exhibit monopoly characteristics (i.e. there is more than one service provider in the industry); and (ii) the regulation of persons providing EV charging services who are not a public utility is not required to protect consumers as competition will ensure that the service providers are unable to practice monopolistic behaviour affecting rate prices. In Phase II, BCUC will examine the regulatory framework for EV charging service providers who are currently considered a public utility (e.g. BC Hydro and FortisBC) and who would not fall under the BCUC exemption as recommended in the Phase I report.

ALBERTA

- **Alberta transitions to Carbon Competitiveness System in January 2018:** The *Carbon Competitiveness Incentive Regulation* ("CCI Regulation") replaced the *Specified Gas Emitters Regulation* on January 1, 2018. Under the CCI Regulation, large emitters in Alberta are allowed to emit a certain amount of GHG, free of charge from the carbon levy. This approach is designed to protect industries from competitiveness impacts that could shift production to other jurisdictions. The CCI Regulation applies to facilities that emitted 100,000 tonnes or more of GHG in 2003, or a subsequent year. A facility with less than 100,000 tonnes of GHG may be eligible to opt-in to the CCI Regulation if it competes against a facility regulated under the CCI or has more than 50,000 tonnes of annual emissions, high emissions-intensity and trade-exposure (by opting in, facilities become exempt from the application of the carbon levy for fuels whose emissions are included in their site reporting). Under the updated system, a facility will receive performance credits if their greenhouse gas emissions are less than the amount freely permitted.
- If their emissions are above the amount freely permitted, they will be required take one or more of the following actions to bring the facility into compliance:
  - make improvements at their facility to reduce emissions intensity;
  - use emission performance credits generated at facilities that achieve more than the required reductions;
  - purchase Alberta-based carbon offset credits; or
  - contribute to Alberta's Climate Change and Emissions Management Fund.

- **New Conservation and Reclamation Directive for Renewable Energy Operations:** In September 2018, Alberta Environment and Parks ("AEP") released its new *Conservation and Reclamation Directive for Renewable Energy Operations*. The Directive sets out requirements that renewable energy operations ("REOs") must abide by in developing and implementing conservation and reclamation plans for wind, solar and geothermal electricity projects. As of September 14, 2018, all operators of REOs, including those with commissioned or pending applications, are required to do the following under the Directive: (a) complete interim monitoring site assessments following disturbances (i.e. clearing vegetation) associated with the construction or operation of a project; (b) develop or update its conservation and reclamation plan ("C&R Plan") under designated circumstances; and (c) complete reclamation certificate site assessments for disturbed areas, submit a reclamation certificate application, and obtain a reclamation certificate. Any REOs that submit a project application to the Alberta Utilities Commission ("AUC") before January 1, 2020 are considered to have met the Directive's requirement for a C&R Plan by submitting an Environmental Evaluation / Environmental Plan. Any application submitted to the AUC on or after January 1, 2020 must meet the C&R plan requirements under the Directive.

- **Amendments to AUC Rules for Wind and Solar Power Plants Regarding Impacts on Wildlife:** Effective April 2, 2018, the AUC amended Rule 007, requiring all applications for the construction, operation, or alteration of wind and solar power plants to now include a signed renewable energy referral report from AEP Wildlife Management. This new rule is intended to ensure solar and wind power plants in Alberta are implementing measures to reduce potentially negative impacts on wildlife, in accordance with AEP's *Wildlife Directive for Alberta Wind Energy Projects* and *Wildlife Directive for Alberta Solar Energy Projects*.
- **Methane Emissions Reduction Plan:** Alberta's *Climate Leadership Plan* includes a goal of reducing methane emissions by 45% (relative to 2014 levels) by 2025. The new Methane Emissions Reduction program is intended to help small and medium sized oil and gas companies reduce methane emissions. Oil and gas facilities with production in Alberta not exceeding 40,000 BOE/day are eligible for the program, which offers up to $250,000 in funding per facility, per fiscal year. Funding can be used by an owner to conduct a study to identify eligible capital projects that reduce methane emissions or if such a study has already been conducted, an owner can apply directly for capital project funding. AER's new regulatory requirements supporting methane emissions reduction can be found in *Directive 017: Measurement Requirements for Oil and Gas Operations*, effective December 13, 2018 and *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*, effective January 1, 2020.
- **Cap on Oil Sands Emissions Delayed:** While the *Oil Sands Emissions Limit Act* came into force on December 14, 2016 (legislating a 100 Mt per year greenhouse gas emission cap from oil sands production), the cap has yet to be enforced in Alberta. In December 2018,

the Government of Alberta stated it was still conducting stakeholder consultations and did not expect the cap to be in place prior to Alberta's May 2019 election.

ONTARIO

- **Cap-and-Trade Program Cancellation.** Following through with one of its campaign promises, the newly elected Progressive Conservative government cancelled the province's cap-and-trade program. Bill 4, the *Cap and Trade Cancellation Act*, 2018, received Royal Assent in October 2018. Ontario's Cap-and-Trade Program began on January 1, 2017 and raised (prior to its cancellation) approximately $2.8 billion through government-held auctions that sold credits to companies who were required to comply with the program, as well as to those who were voluntarily part of the program. The *Cap and Trade Cancellation Act, 2018* includes a scheme to compensate some holders of cap-and-trade credits for a portion of the credits they purchased. However, compensation will not be provided to market participants, electricity importers, natural gas distributors, participants who operate equipment related to the transmission, storage or transportation of natural gas in Ontario, petroleum product suppliers, electricity transmission systems operators, and electricity generators. Regulations prescribing the formula for compensation are still pending. The Act specifically prohibits any other compensation related to the value of cap and trade credits that were retired or cancelled under the Act.

  Following the cancellation of Ontario's cap-and-trade program, the federal government announced that Ontario will be one of the provinces that is subject to the federal carbon pricing backstop system for GHGs, as it does not have in place a GHG pricing system that meets federal requirements. For larger industrial facilities, an output-based pricing system for emissions-intensive trade-exposed ("EITE") industries will start applying in January 2019 (which will cover facilities emitting 50,000 tonnes of carbon dioxide equivalent ("CO2e") per year or more, with the ability for smaller EITE facilities that emit 10,000 tonnes of CO2e per year or more to voluntarily opt-in to the system over time). The federal fuel charge, which will generally be paid by registered fuel producers and distributors, will apply starting in April 2019.

- **Constitutional Challenge to the Federal Government's Pollution Pricing Regime:** In September 2018, the Ontario government launched a constitutional challenge to the federal government's GHG carbon pricing backstop system. Ontario is arguing that the federal government does not have the jurisdiction to impose a carbon price on the province. This challenge is moving through the courts and is expected to be heard sometime in 2019.

- **Ontario's Environmental Plan:** On November 29, 2018, the Ontario government released its *Environment Plan: Preserving and Protecting our Environment for Future Generations*. The Plan provides a broad outline of the government's intended actions and policies for addressing many environment-related issues in Ontario, including the pollution of air, land, and water, the reduction of litter and waste, and the emission of GHG. With respect to GHG emissions, the Plan indicates that the government will develop and implement policies to encourage the use of low carbon vehicles, and that it will implement industry-specific emissions performance standards (that are tied to a level of output or production of a facility, without a cap), increase the required ethanol content in gasoline, and establish an

Ontario Carbon Trust to assist in funding projects that will reduce the emission of GHG at the lowest cost. Following public consultation, the government intends to establish an advisory panel on climate change and to begin implementing some of the initiatives identified in the Plan.

- **Renewable Energy Approval Regulation Amendment:** The Ontario government posted a proposal to amend the *Renewable Energy Regulation* under the *Environmental Protection Act* such that a project developer is required to show that there is demand for the electricity they will generate in order to obtain a renewable energy approval. The proposal would affect new renewable energy approval applicants as well as those whose applications are under review when the regulation comes into force. The amended regulation is expected following the public consultation period.

QUÉBEC

- **Modernization of *Environment Quality Act*:** On March 23, 2018, the majority of the provisions of Bill 102 (the “Act 102”) came into force. Act 102, which was passed by the National Assembly in March 2017, is aimed at modernizing the environmental authorization scheme under the Québec *Environment Quality Act*. Under the new regime, public access to various environmental and permitting documents filed by proponents with the Québec Ministry of Environment and the Fight against Climate Change (“MEFCC”) is now easier. Furthermore, Act 102 modified the environmental impact assessment (“EIA”) and review process for major projects. The Government may now subject any project to the EIA process if, in its opinion, the project (i) may raise major environmental issues and public concern warrants it, (ii) involves a new technology or new type of activity in Québec with major anticipated impacts on the environment; or (iii) involves major climate change issues. A new list of projects subject to the EIA was also introduced upon the coming into force of the *Regulation respecting the environmental impact assessment and review of certain projects*. Furthermore, on February 14, 2018, a series of draft regulations to implement the legal reform was published in the *Gazette officielle du Québec*. However, due to concerns raised by a number of organizations and experts mandated by the former Liberal government, the enactment of the regulations was postponed. The recently elected CAQ government indicated it did not intend to cancel the reform. Advisory groups will be formed in early 2019 in order to continue the work on the draft regulations. A transitory scheme introduced on March 23, 2018 is expected to be maintained until the regime is fully implemented.

- **New Wetlands Compensation Regime:** A new wetlands compensation regime was implemented in Québec on September 20, 2018, the date on which the *Regulation respecting compensation for adverse effects on wetlands and bodies of water* came into force (the “Regulation”). This follows the adoption on June 16, 2017 of Bill 132, an *Act respecting the conservation of wetlands and bodies of water* (the “Act 132”), which reformed the legal framework applicable to wetlands and bodies of water (“WBW”) in Québec to increase their conservation and enshrines the principle of “no net loss” of WBW. Under the new regime, proponents are required to demonstrate to the satisfaction of the MEFCC that there is no other space available for the purposes of the project and that the project has been designed to minimize impacts on WBW. If a proponent is able to convince the MEFCC that destruction of WBW should be authorized, a significant monetary compensation, calculated based on the formula set forth in the Regulation, has to be paid by the proponent to the Government to finance WBW restoration and conservation projects. The formula takes into account the initial state of a given WBW and the expected impact of the contemplated activity thereon as well as the relative scarcity of WBW in a given region. In limited circumstances, the MEFCC may authorize the substitution of the monetary compensation by work carried out to restore or create WBW.

FEDERAL

- **Legislation for Proposed New Impact Assessment Process:** On February 8, 2018, the federal government introduced new rules for environmental assessment under Bill C-69, the *Impact Assessment Act* ("Bill C-69"), which is designed to replace the current *Canadian Environmental Assessment Act, 2012*. A key highlight of Bill C-69 is replacing the National Energy Board with the Canadian Energy Regulator and establishing a new Canadian Impact Assessment Agency ("IAA") for resource project reviews. Under Bill C-69 and its regulations, a list of projects subject to review by the IAA will be provided, which list has not yet been published. The government has suggested, however, that this list could include projects that had previously been excluded from such federal review.
- **Legislation for Proposed Changes to Fisheries Act Regime:** Bill C-68 was introduced by the federal government on February 6, 2018, which proposes amendments to restore lost protections and incorporate modern safeguards into the *Fisheries Act*. Bill C-68 is currently under review by the Senate, which referred the Bill to the Standing Senate Committee on Fisheries and Oceans on December 11, 2018.
- **Legislative Framework for Federal Carbon Pricing Backstop is Established:** The *Greenhouse Gas Pollution Pricing Act* received Royal Assent in June 2018, which includes a two-pronged approach to carbon pricing: (i) a charge on fossil fuels that are consumed within a province, which will be administered by the Canada Revenue Agency (the fuel charge will generally be paid by fuel producers and distributors); and (ii) an output-based pricing system ("OBPS") that applies to emission-intensive industrial facilities, which will be administered by Environment and Climate Change Canada. On October 24, 2018, the federal government confirmed its plan to move forward with a federal carbon pricing system in 2019. The Department of Finance has outlined plans for the proceeds from the fuel charge to be returned directly to individuals and families in backstop jurisdictions through the Climate Action Incentive.

The year ahead

BRITISH COLUMBIA

- **Revitalized Environmental Assessment Process to Come Into Force:** Bill 51 is expected to come into force in late 2019, once key supporting regulations and policies have been developed. As a priority, EAO will be developing the following regulations: (i) Reviewable Projects Regulation; (ii) Regional Assessments; (iii) Dispute Resolution; and (iv) Fees and Funding.

ONTARIO

- **Ontario's GHG Pricing Program:** As noted above, the Ontario government is challenging the constitutionality of the federal government's carbon pricing backstop on the basis that the federal government does not have the jurisdiction to impose carbon pricing in the province. While this challenge moves through the courts, the federal backstop will be in effect as of January 1, 2019. Before the end of 2019, we will likely have certainty on whether the federal government's carbon pricing backstop is valid in Ontario.

- **Evolution of Ontario's Environment Plan:** As outlined in its Plan, the Ontario government will begin implementing initiatives to reduce carbon emissions in Ontario. In 2019, depending on the outcome of the government's constitutional challenge to the federal pricing regime, we may see provincial initiatives aimed at reducing GHG emissions, such as the establishment of an Ontario Carbon Trust that provides assistance in funding lowest costs GHG reduction projects, come into force. The Ontario government is consulting with industry on emission performance standards (part of the Environment Plan) and has indicated that it is exploring ways to recycle any funding collected through the implementation of such standards back to industry to finance further GHG reduction technologies. We can expect to see more about these initiatives in early 2019.

QUÉBEC

- **New Regulations to Support Act 102:** As noted above, the majority of the provisions of Act 102 came into force on March 23, 2018. Advisory groups will be formed in early 2019 in order to continue work on draft regulations to support the modernization of the environmental authorization scheme under the Québec *Environment Quality Act*. A transitory scheme introduced on March 23, 2018 is expected to be maintained until the regime is fully implemented.

FEDERAL

- **Proposed New *Impact Assessment Act* and Changes to *Fisheries Act* to Come into Force:** At the time of writing, both Bill C-68 and Bill C-69 are under review by the Senate. The new impact assessment legislation and amendments to the *Fisheries Act* are expected to come into force in 2019.

- **Federal Carbon Pricing Backstop to Apply in 2019:** As noted above, the federal government has confirmed its plan to move forward with a federal carbon pricing system in 2019. The federal government had previously announced that it would apply a federal backstop price on pollution to provinces or territories that did not have their own carbon pricing systems in place or that did not meet the federal requirements. The key requirement is to have a price on carbon of $20 per tonne starting in 2019 to increase by $10 per tonne annually until it hits $50 per tonne in 2022. The federal carbon pricing backstop will be implemented (either entirely or in part) in Saskatchewan, Manitoba, Ontario, New Brunswick, Yukon, Nunavut, and Prince Edward Island. A more detailed overview of carbon pricing initiatives across Canada, as well as an update on the status of the implementation of the Paris Agreement, can be found on page 37 of this publication.

– **Constitutional Challenges to Federal Carbon Pricing Backstop:** In addition to Ontario, Saskatchewan has launched a legal challenge to the federal government's jurisdiction to impose a federal carbon pricing system on the provinces. Saskatchewan's constitutional reference case against the federal backstop system will be heard by the Saskatchewan Court of Appeal on February 13 and 14, 2019. Saskatchewan is arguing that the federal carbon tax is unconstitutional as it applies a tax unevenly across provinces and territories. The Ontario challenge argues that the province should have and already has the ability to regulate GHG emissions themselves, and that the backstop system imposed by the federal government is not a valid regulatory charge or valid taxation. The Ontario case is expected to be heard in April 2019. In December 2018, New Brunswick also announced that it will launch its own legal challenge of the federal carbon pricing backstop.

We'll Always Have Paris: UNFCCC Parties Move Forward on Implementing Paris Agreement and Update on the State of the (Carbon Pricing) Nation in Canada

Author: Selina Lee-Andersen

Following two weeks of tense negotiations at the recent 24th Conference of the Parties ("COP24") held in Katowice, Poland, negotiators from 196 countries and the European Union finalized the Katowice Climate Package, which seeks to put the meat on the proverbial bones of the Paris Agreement. As a refresher, the Paris Agreement was adopted at COP21 in 2015 and establishes a goal of limiting the global average temperature increase to well below 2°C above pre-industrial levels, while pursuing efforts to limit it to 1.5°C. The Paris Agreement also provides that each party will communicate successively more ambitious Nationally Determined Contributions ("NDCs") at five-year intervals. Other features of the Paris Agreement include provisions on adaptation, finance, technology, compliance, transparency, and a process known as the global stocktake beginning in 2023, when parties will convene this process at five-year intervals to review collective progress on mitigation, adaptation and implementation. As part of the Paris Agreement, parties established the Ad hoc Working Group for the Paris Agreement, which has been tasked with developing the operational details through the Paris Agreement Work Programme ("PAWP").

COP 24 brought together more than 22,000 participants, whose discussions were focused on completing the PAWP. The Katowice Climate Package covers decisions on almost all of the issues mandated under PAWP, including:

- **Mitigation:** Development of further guidance on NDCs, common timeframes and modalities, work programme, and functions of the forum on the impact of the implementation of response measures under the Paris Agreement.
- **Adaptation:** Development of further guidance on adaptation communication.
- **Finance:** Identification of information to be provided by parties in accordance with Article 9.5 of the Paris Agreement (ex ante finance transparency) and matters relating to the Adaptation Fund, and setting a collective quantified goal on finance from a floor of US $100 billion per year.
- **Technology:** Adoption of decisions on the scope of, and modalities for, the periodic assessment of the Technology Mechanism and the technology framework.
- **Other Issues:** Discussions around the modalities, procedures and guidelines for the transparency framework for action; the global stocktake; and modalities and procedures for the effective operation of the committee to facilitate implementation and to promote compliance.

In addition, Ministers attending COP24 adopted the "Forests for Climate" Katowice Ministerial Declaration[1], pursuant to which the Ministers have pledged to accelerate actions to ensure that the global contribution of forests and forest products is maintained and further supported and enhanced by 2050 to support achievement of the Paris Agreement goals. A list of parties supporting the Declaration (which includes Canada) is available online.[2]

The draft decisions on matters relating to the implementation of the Paris Agreement is available online[3] (the official version and the translations will be made available on the UNFCCC web site[4] as soon as they are issued by the United Nations Office in Geneva). The Katowice Climate Package marks a successful outcome despite shifting political winds in certain jurisdictions and the technical complexities of the matters at hand. However, a number of challenging decisions (including those around strengthening ambition around emission reduction goals, and setting the rules for voluntary market mechanisms) have been put off until COP25 to be held in Chile in 2019. Whether the Katowice Climate Package will provide a sufficiently robust framework for implementing the Paris Agreement and for actions post-2020 remains to be seen.

At COP24, Canada played a leading role in advancing various emission reduction initiatives under the Paris Agreement, including laying the groundwork for a global carbon market, promoting the Powering Past Coal Alliance[5] (which Canada and the United Kingdom founded at COP23), and advancing the work of the Local Communities and Indigenous Peoples Platform[6]. Back home, the federal government is implementing initiatives to advance the *Pan Canadian Framework on Clean Growth and Climate Change*[7], including the implementation of the federal carbon pricing system in backstop jurisdictions in 2019. Under the *Greenhouse Gas Pollution Pricing Act*[8] ("GGPPA"), the federal carbon pricing system consists of two components:

The **Katowice Climate Package** marks a successful outcome despite shifting political winds in certain jurisdictions and the technical complexities of the matters at hand.

- a federal fuel charge; and
- a regulatory trading system for large emitters (i.e. facilities with emissions ≥ 50,000 tonnes of carbon dioxide equivalent) – the federal Output-Based Pricing System ("OBPS").

1 https://cop24.gov.pl/fileadmin/user_upload/Ministerial_Katowice_Declaration_on_Forests_for_Climate_OFFICIAL_ENG.pdf
2 https://cop24.gov.pl/fileadmin/user_upload/files/Forest_for_climate_declaration_list_of_countries_supporting_declaration.pdf
3 https://unfccc.int/sites/default/files/resource/l04_4.pdf
4 https://unfccc.int/documents
5 https://poweringpastcoal.org/
6 https://unfccc.int/10475
7 https://www.canada.ca/en/services/environment/weather/climatechange/pan-canadian-framework/climate-change-plan.html
8 https://laws-lois.justice.gc.ca/eng/acts/G-11.55/index.html

The following provides an overview of carbon pricing initiatives across all the provinces and territories as of January 1, 2019:

- **British Columbia -** Carbon tax of $35 per tonne; rising $5 per tonne on April 1st until it reaches $50 per tonne by 2021.

  Key Policy Document: CleanBC Plansasa[9]

- **Alberta -** Carbon levy of $30 per tonne; no planned increases until further notice.

  Key Policy Document: Climate Leadership Plan[10]

- **Saskatchewan -** The federal backstop will be implemented, in part, in Saskatchewan:

  - Federal fuel charge to apply from April 2019 (generally paid by registered fuel producers and distributors).
  - Saskatchewan implemented its output-based performance standards system on January 1, 2019 (applicable to industrial facilities that emit 25,000 tonnes or more of carbon dioxide equivalent ("CO2e") per year).
  - Federal OBPS will apply to electricity generation and natural gas transmission pipelines (which are not covered by the provincial program) beginning in January 2019 (applicable to facilities from those sectors that emit 50,000 tonnes of CO2e per year or more, with the ability for smaller facilities that emit 10,000 tonnes of CO2e per year or more to voluntarily opt-in to the system over time).

  Key Policy Document: Prairie Resilience: A Made-in-Saskatchewan Climate Change Strategy[11]

- **Manitoba** - The federal backstop will be implemented in Manitoba:

  - Federal fuel charge to apply from April 2019 (generally paid by registered fuel producers and distributors).
  - Federal OBPS will start applying in January 2019 (applicable to emissions-intensive trade-exposed ("EITE") facilities emitting 50,000 tonnes of CO2e per year or more, with the ability for smaller EITE facilities that emit 10,000 tonnes of CO2e per year or more to voluntarily opt-in to the system over time).

  Key Policy Document: A Made-in-Manitoba Climate and Green Plan[12]

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9 https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_2018-bc-climate-strategy.pdf

10 https://www.alberta.ca/climate-leadership-plan.aspx

11 http://www.saskatchewan.ca/business/environmental-protection-and-sustainability/a-made-in-saskatchewan-climate-change-strategy/prairie-resilience

12 https://www.gov.mb.ca/climateandgreenplan/index.html

- **Ontario -** The federal backstop will be implemented in Ontario (on the same basis as described above for Manitoba).

  Key Policy Document: Preserving and Protecting our Environment for Future Generations: A Made-in-Ontario Environment Plan[13]

- **Québec -** Cap & Trade System with an allowance price of $20.27 (November 14, 2018 Auction)

  Key Policy Document: 2013-2020 Climate Change Action Plan[14]

- **New Brunswick -** The federal backstop will be implemented in New Brunswick (on the same basis as described above for Manitoba).

  Key Policy Document: Transitioning to a Low-Carbon Economy: New Brunswick's Climate Change Action Plan[15]

- **Nova Scotia -** Cap-and-trade program started on January 1, 2019.

  Key Policy Document: Climate Change Action Plan[16]

- **Prince Edward Island -** The federal backstop will be implemented, in part, in PEI:

  - A carbon levy on fuel will come into force on April 1, 2019.
  - Federal OBPS will start applying in January 2019 (applicable to EITE facilities emitting 50,000 tonnes of CO2e per year or more, with the ability for smaller EITE facilities that emit 10,000 tonnes of CO2e per year or more to voluntarily opt-in to the system over time).

  Key Policy Document: Climate Change Action Plan 2018-2023[17]

- **Newfoundland & Labrador -** Newfoundland & Labrador's carbon pricing plan will came into force on January 1, 2019:

  - Provincial carbon tax rates shall commence at $20 per tonne on January 1, 2019. The provincial Gasoline and Diesel Tax will be adjusted with a goal of Atlantic parity related to provincial taxation (including carbon tax) of fuel products. The carbon tax rates will only increase based on changes to Atlantic parity that allows for rate increases.

13 https://prod-environmental-registry.s3.amazonaws.com/2018-11/EnvironmentPlan.pdf
14 http://www.environnement.gouv.qc.ca/changementsclimatiques/plan-action-fonds-vert-en.asp
15 https://www2.gnb.ca/content/dam/gnb/Departments/env/pdf/Climate-Climatiques/TransitioningToALowCarbonEconomy.pdf
16 https://climatechange.novascotia.ca/sites/default/files/Climate-Change_English.pdf
17 https://www.princeedwardisland.ca/en/information/communities-land-and-environment/climate-change-action-plan-2018-2023

- A performance-based system for offshore and onshore industries will establish GHG reduction targets for large industrial facilities and large scale electricity generation.
- Exemptions from the carbon tax are available for agriculture, fishing, forestry, offshore and mineral exploration, and methane gases from venting and fugitive emissions in the oil and gas sector.

Key Policy Document: Charting Our Course: Climate Change Action Plan 2011[18]

- **Nunavut -** The federal backstop will be implemented in Nunavut (on the same basis as described above for Manitoba, except that both the federal fuel charge and federal OBPS will apply from July 2019).

  Key Policy Document: Upagiaqtavut: Climate Change Impacts and Adaptation in Nunavut[19]

- **Yukon -** The federal backstop will be implemented in Yukon (on the same basis as described above for the Nunavut).

  Key Policy Document: Yukon Government Climate Change Action Plan[20]

- **Northwest Territories -** Northwest Territories will introduce a carbon tax on fuels effective July 1, 2019 based on $20 per tonne of GHG emissions. This will increase annually to $50 per tonne.

  Key Policy Document: 2030 NWT Climate Change Strategic Framework[21]

18 https://www.exec.gov.nl.ca/exec/occ/publications/climate_change.pdf
19 http://www.climatechangenunavut.ca/sites/default/files/3154-315_climate_english_reduced_size_1_0.pdf
20 http://www.env.gov.yk.ca/air-water-waste/climatechange.php
21 https://www.enr.gov.nt.ca/en/services/climate-change/2030-nwt-climate-change-strategic-framework

Aboriginal Law

Authors: Bryn Gray, Selina Lee-Andersen, and Stephanie Axmann

Aboriginal law is continually evolving area for energy and resource development in Canada. Each passing year brings new developments and 2018 was no exception. Some of the key cases are highlighted below:

Federal Court of Appeal Halts Another Pipeline Project

The most widely publicized and discussed Aboriginal law case this year was undoubtedly the Federal Court of Appeal's decision to quash the federal government's approval of the Trans Mountain Expansion project (the "TMX Project"). This is the second time in three years that Canada's Federal Court of Appeal (the "FCA") has halted the development of a proposed interprovincial pipeline project to bring Alberta's oil to tidewater for export to Asian markets.

The approval was quashed on the basis that (i) the Crown's duty to consult with Indigenous groups had not been met and (ii) the National Energy Board ("NEB") did not adequately assess the impact of increased tanker traffic on marine life. We have set out below a summary of the decision and its key findings along with a discussion about its potential implications.

OVERVIEW OF THE TMX PROJECT & THE FCA'S DECISION

The TMX Project is a proposed twinning of an existing oil pipeline from Edmonton, Alberta to Burnaby, BC, with approximately 89% of the route being parallel to existing linear disturbances. The TMX Project would almost triple the overall capacity of the pipeline system from 300,000 barrels a day to 890,000 barrels a day. It is also projected to bring an over 6-fold increase in the number of tankers at the Westridge Marine Terminal in Burnaby from approximately 5 per month to 34 per a month.

The TMX Project was approved by the federal Cabinet on November 29, 2016 upon the recommendation of the NEB, which concluded that the TMX Project was in the public interest and was unlikely to cause significant adverse environmental effects if certain conditions and mitigation measures were implemented. Indigenous groups had the opportunity to participate in the NEB process and the then proponent and federal officials undertook further consultation outside of the NEB process. After the approval was granted by the federal government, numerous parties subsequently commenced judicial reviews, including two municipalities, two environmental groups, and five Indigenous groups/collectives.

Duty to Consult

Similar to the FCA's decision quashing the Northern Gateway approval, the FCA quashed the approval based primarily on deficiencies in the consultation undertaken by federal officials in the last phase of the project review prior to the Cabinet decision. The FCA identified four overarching flaws that resulted in "an unreasonable consultation process that fell well-short of the required mark."

First, the FCA found that there was a lack of meaningful two-way dialogue during the meetings between Indigenous groups and federal officials. This was primarily because the officials were only empowered to take notes and relay concerns back to decision-makers. The FCA concluded that there was a lack of "a genuine and sustained effort to pursue meaningful, two-way dialogue" and when responses were provided by federal officials, they were generally brief or generic and did not further dialogue.

Second, the FCA criticized Canada's perceived unwillingness to depart from the NEB's findings and recommended conditions despite numerous concerns being raised about the hearing process and the NEB's findings. This included the exclusion of project-related shipping from the environmental assessment under the *Canadian Environmental Assessment Act, 2012* (CEAA 2012), the proposed pipeline route, and deficiencies in the NEB's recommended conditions, among other things. The FCA found that Canada displayed a close-mindedness to concerns about the NEB's report and that it was "obliged to do more than passively hear and receive the real concerns of Indigenous applicants."

Third, the FCA held that Canada erroneously took the position that it was unable to impose additional conditions on Trans Mountain beyond the conditions recommended by the NEB. The FCA found that Canada's unwillingness to impose additional conditions on the proponent limited the scope of necessary consultation and possible accommodation, although at the same time the FCA disregarded certain measures introduced to respond to concerns of Indigenous groups as they were still being developed and it was unclear to the FCA whether these initiatives would address the concerns.

Fourth, Canada disclosed its assessment of the TMX Project's impacts on the Indigenous applicants less than a month before issuing its project approval, finding that the TMX Project would not have a high level of impact on asserted and established Indigenous rights. The FCA found that this gave little time to the Indigenous groups to respond to these assessments and, despite undertaking consultation at the deep end, the FCA concluded that Canada's view of the TMX Project's impacts influenced its assessment of both the reasonableness of its consultation and accommodation efforts.

Scope of Environmental Assessment

In addition to the duty to consult findings, the FCA held that the NEB was not justified in excluding project-related shipping from the environment assessment under CEAA 2012. The FCA held that the exclusion of this issue from the CEAA 2012 EA allowed the NEB to conclude that the TMX Project was not likely to cause significant adverse effects. This was notwithstanding the fact that the NEB did separately review marine shipping issues under the NEB Act and concluded the operation of project-related marine vessels was likely to cause significant adverse effects to the Southern resident killer whale, an endangered species. This conclusion was before the federal Cabinet when it made its decision. The FCA also found that the NEB's report did not give the federal Cabinet the information it needed to make a decision primarily due to a lack of sufficient consideration of mitigation measures relating to the impacts on the Southern resident killer whale. The NEB did consider mitigation measures within its jurisdiction but, in order to substantially comply with the Species at Risk Act, the FCA's view was that the federal Cabinet required the NEB's exposition of all technically and economically feasible measures that are available to avoid or lessen the TMX Project's effects on the Southern resident killer whale. Without this information, the Governor in Council lacked the necessary information to make the decision required of it.

Based on its findings regarding the duty to consult and marine shipping, the FCA quashed the project approval and remitted it to the federal Cabinet for prompt redetermination. However, it directed the federal government to refer the matter back to the NEB for reconsideration on a number of matters relating to marine shipping. The FCA also held that Canada must redo its Phase III consultation after the NEB issues a revised report, and that only after that consultation is completed can the matter be put back before the federal Cabinet for approval. The federal government has since referred the matter back to the NEB to reconsider the findings and recommendations in its report related to marine shipping and the NEB must submit their report by February 22, 2019. Canada has also appointed former Supreme Court of Canada Justice Frank Iacobucci to lead the consultation process with Indigenous groups both before and after the NEB issues its revised report. Based on the timing of the NEB report, it is anticipated that the federal government will issue a decision on the TMX Project prior to the fall 2019 federal election.

IMPLICATIONS OF THE DECISION

In our view, there are a number of notable takeaways from this decision relating to the duty to consult.

First, the overarching message is that consultation must be *meaningful*. It is not simply a process to exchange information and document concerns. This decision is part of a general judicial trend that has seen an increasing emphasis on and scrutiny of the meaningfulness of consultation. However, the FCA arguably went even further in the extent of its detailed and scrutinizing examination of the consultation and accommodation in light of the specific issues raised by each of the Indigenous applicants. In so doing, the FCA emphasized the importance of two-way dialogue, although the reasons appear to suggest that direct verbal dialogue between Indigenous groups and the decision-makers or senior government officials was required in order for consultation to be meaningful. In our view, this is inconsistent with prior Supreme Court of Canada ("SCC") jurisprudence and disregards the practical implications of imposing such a requirement on government decision-making. The FCA also went beyond existing jurisprudence in disregarding certain accommodation measures that had been announced but not fully developed, which would have also likely been an issue on appeal if this had been pursued.

Second, the FCA underscored that, consistent with the SCC's decision in *Clyde River*, consultation must focus specifically on the impacts on Indigenous rights, rather than biophysical impacts – noting that "the consultation inquiry is not properly into environmental effects per se. Rather, it inquires into the impact on the *right*." The FCA also emphasized that when a project has the potential to affect multiple Indigenous communities, the impacts on rights need to be individually assessed for each group.

Third, the decision emphasizes the importance of demonstrating the meaningfulness of consultation in written reasons and in communications to Indigenous groups, particularly when a duty of deep consultation is owed. The level of scrutiny applied by the FCA to the Crown's written record would again likely have been a focus of any appeal given prior and subsequent jurisprudence but this does underscore the growing importance of written reasons in duty to consult jurisprudence. It also serves as a reminder to both proponents and the Crown of the critical importance of maintaining a robust and complete consultation record that captures all concerns and demonstrates how such concerns have been specifically considered and responded to and/or addressed in a meaningful way.

Fourth, the FCA confirmed once again that the duty to consult does not give Indigenous groups a veto over land decisions pending final proof of their claim, and that there is no duty to agree. Rather, it is a commitment to a meaningful process of consultation. Despite Canada's acknowledgement that several Indigenous groups had strong claims to Aboriginal title in areas potentially affected by the TMX Project, the FCA did not suggest that consent was required or refer to the *United Nations Declaration on the Rights of Indigenous Peoples* ("UNDRIP") and the principle of "free, prior, and informed consent". This reaffirms existing Canadian jurisprudence on the duty to consult and consent. Discussions on this issue will undoubtedly continue as Canada proceeds with implementing UNDRIP. The federal government has stated that it will be implemented in a way that is consistent with the Canadian Constitution, which notably only requires consent in very limited situations such as established Aboriginal title or an unjustifiable infringement of an established Aboriginal or treaty right.

No Duty to Consult in the Legislative Process

Another decision that received significant attention this year was the SCC's decision in *Mikisew Cree First Nation v. Canada*. In this decision, Canada's highest court determined that there is no duty to consult Indigenous groups at any stage of the law-making process. This is an important ruling as the recognition of a justiciable duty to consult in the legislative process would have had very significant implications for the ability of federal, provincial, and territorial governments to pass laws in a timely way, particularly laws relating to environmental assessments, resource management, and the regulation of energy projects. McCarthy Tétrault LLP lawyers, Brandon Kain and Bryn Gray, acted for one of the interveners in this appeal.

This appeal arose from a judicial review by the Mikisew Cree relating to the former Conservative government's introduction of omnibus legislation amending several Canadian environmental and regulatory laws in 2012. The Mikisew Cree were not consulted on the amendments. While the Crown's duty to consult has to date been limited to executive action, the appellant argued that the duty to consult was triggered because the Ministers were acting in an executive (rather than legislative) capacity in developing and introducing legislation and the amendments reduced federal regulatory oversight on projects that may affect their treaty rights to hunt, fish, and trap.

While there were four different judgments, the SCC was unanimous in dismissing the Mikisew Cree's appeal. All nine judges agreed that the Federal Court lacked jurisdiction over the Mikisew Cree's claim because the *Federal Courts Act* does not allow for judicial review of parliamentary activities and actions of Ministers in the parliamentary process. The SCC split (7-2) on whether legislation could be challenged once enacted for a failure to consult Indigenous groups. The majority of the judges in three separate concurring decisions ruled that there could be no duty to consult at any stage of the legislative process as this would be contrary to parliamentary sovereignty, parliamentary privilege, and/or the separation of powers and would raise numerous practical concerns that would disrupt the law-making process.

This decision does not mean that legislation is immune from judicial challenge by Indigenous groups. Laws can still be struck down once enacted if they infringe established Aboriginal or treaty rights or *Charter* rights. The SCC's split ruling with four different judgments also creates uncertainty about whether legislation can be challenged once enacted on additional grounds, specifically a breach of the honour of the Crown. While this suggestion was raised in a minority concurring decision, it will likely lead to further litigation on this point.

Another Unsuccessful Challenge to the Site C Project

In October 2018, West Moberly First Nations ("WMFN") was unsuccessful in obtaining an injunction against the B.C. Hydro and Power Authority ("BC Hydro") from further construction on the Site C hydroelectric dam project (*West Moberly First Nations v. British Columbia, 2018 BCSC 1835*). WMFN sought to enjoin work for 24 months or pending final determination of their claim for infringement, whichever came earlier (except for such measures necessary to ensure safety and to prevent environmental harm). Alternatively, WMFN sought to prohibit work during this period in 13 critical areas of particular importance to the exercise of their rights under Treaty 8.

Site C received its federal and provincial environmental assessment approvals in October 2014. WMFN opposed the project from the outset. Judicial applications seeking to quash Site C's environmental assessment approvals were unsuccessful[22] , and further appeals to the SCC were denied in June 2017. Construction activity commenced in July of 2015 and an interlocutory injunction pending judicial review was refused.[23]

22 See 2017 BCCA 58 and 2017 FCA 15.

23 See 2015 BCSC 2662.

In denying the latest request for an injunction, Justice Milman found that while WMFN raised a serious question to be tried and that there is a risk that WMFN will suffer irreparable harm if an injunction is not granted, he concluded that the balance of convenience lies against granting the injunction sought for the following principal reasons: (i) WMFN's underlying claim that the project unjustifiably infringes their treaty rights is not particularly strong; (ii) an injunction will cause delays and result in substantial cost increases, which in turn will cause harm to ratepayers and other project stakeholders, including other First Nations looking to benefit from the project economically; and (iii) the application was "inexcusably commenced well over two years after construction began compounding the prejudice to the defendants and third parties that would flow from an injunction". Justice Milman noted that: "if an injunction is granted but the claim turns out to be unsuccessful on the merits, one of the most important public infrastructure projects undertaken in decades will be needlessly put into disarray". While the Court did not order an injunction, it directed the parties to agree on a schedule that would lead to a conclusion of the trial of WMFN's action by no later than mid-2023.

Federal Court of Appeal Underscores Reciprocal Obligations of Indigenous Groups

In May 2018, the FCA dismissed a judicial review of the federal government's approval of the Nova Gas Transmission System Expansion project in northern Alberta. In *Bigstone Cree Nation v. Nova Gas Transmission Ltd.*, the Bigstone Cree Nation alleged that Canada had breached its duty to consult and that the decision was unreasonable. The project at issue provides for 230 km of new pipeline but the application for judicial review related to a 56 km stretch of this new pipeline which is located entirely on provincial Crown land and paralleled existing rights-of-way and other disturbances for 93% of the route. The project was approved by the federal Cabinet on recommendation of the NEB, which had concluded that the potential impacts to the rights and interests of Aboriginal groups would be appropriately mitigated given the nature and scope of the project, the proposed mitigation measures, regulatory requirements, proponent commitments, and the conditions imposed by the NEB.

In dismissing this judicial review, the FCA found that consultation was meaningful and underscored the reciprocal obligations of Indigenous groups, finding that "Bigstone did not live up to its part of the bargain" by not being responsive to Crown requests for meetings. The FCA noted that "good faith on both sides is required" and held that three of the four months set aside for consultation were lost as a result of Bigstone's lack of engagement. The FCA concluded that the Crown was justified in not granting Bigstone's request for more time given their delay and the fact that there had already been a two-month extension.

In addition, the FCA also dismissed Bigstone's arguments about the adequacy of written reasons and that many of the project conditions are prospective and contemplate future consultation by the NEB or proponent when the duty to consult must be fulfilled by the Crown before the federal Cabinet makes a decision on the project. Applying principles from administrative law, the FCA held that the decision-maker does not need to provide reasons on each and every issue and may rely on and adopt the reports of other administrative actors.

The FCA also found that the NEB process and environmental assessments are dynamic processes and it is reasonable that there would be forward looking conditions for further assessment and information, noting based on previous SCC jurisprudence that the project approval is "simply one stage in the process by which a development moves forward".

This FCA panel seemingly takes a different approach to written reasons and prospective mitigation/accommodation in comparison to the one taken by the panel of the same court in Trans Mountain a mere four months later. The approach of the FCA in *Bigstone Cree* is arguably more consistent with a reasonableness standard and the weight of the jurisprudence on these specific issues. It, along with other case law, will likely provide a useful counterpoint for proponents facing similar arguments based on the Trans Mountain decision.

NEB Orders Crown Land Offset Plan to Address Indigenous Concerns for Hydro Line

Cumulative impacts on asserted or established Aboriginal and treaty rights are frequently raised in project reviews and continue to be a challenging issue for Indigenous consultation and accommodation relating to energy projects in Canada. In response to concerns about cumulative impacts from the taking up of Crown land in Manitoba, the NEB recently ordered Manitoba Hydro to develop a plan to offset or compensate for the loss of Crown lands available for traditional use by Indigenous peoples as part of its approval of Manitoba Hydro's proposal for a new international transmission line. While offset plans have previously been developed in response to a variety of issues, the imposition of this condition is a novel response to cumulative impact concerns of Indigenous groups.

Bigstone Cree, along with other case law, will likely provide a useful counterpoint for proponents facing similar arguments based on the Trans Mountain decision.

The project at issue was a proposal to construct a 213 km transmission line consisting of approximately 121 km of new right of way, only 36 km of which would be on Crown land, with less than 10% of the overall route crossing unoccupied Crown lands. The Board found the anticipated land requirements and route selection process to be reasonable and appropriate. However, in response to concerns about dwindling unoccupied Crown land to exercise treaty rights or traditional activities, the Board concluded that this taking up of land could place burdens and challenges on affected First Nations and Métis communities. Despite the objection of Manitoba Hydro, the Board imposed a condition on the proponent to develop a Crown Land Offset Measures Plan as set out below:

> 22. Crown land Offset Measures Plan
>
> Manitoba Hydro must file with the Board, 30 days prior to commencing operations, a Crown Land Offset Measures Plan (the Plan) that outlines how permanent loss of crown

lands available for traditional use by Indigenous Peoples resulting from the Project will be offset or compensated for. The Plan must include:

a) A description of site-specific details and maps showing the locations where Crown land is no longer available for traditional use as a result of Project activities at Dorsey Converter Station and the transmission tower locations, as well as any other locations;

b) A list of offset or compensation measures that will be implemented to address the permanent loss of crown lands identified in a) above;

c) An explanation of the expected effectiveness of each offset measure described in b);

d) The decision-making criteria for selecting specific offset measures that would be used and under what circumstances;

e) A schedule indicating when measures will be implemented and the estimated completion date(s); and,

f) Summary of consultation by Manitoba Hydro with any impacted Indigenous communities and with relevant provincial and federal authorities regarding the Plan.

Proponents have in the past agreed to land offset plans in response to various issues. However, this decision is unique given the nature of the project and that an offset plan was imposed by the decision-maker in response to Indigenous concerns, despite the objection of the proponent. It remains to be seen whether this will become a common condition to address cumulative impact concerns relating to the taking up of Crown land although it will likely, at a minimum, increase expectations of Indigenous groups for future projects involving Crown land.

Crown Contemplation of Funding for Projects May Trigger the Duty to Consult

In November 2018, the Nova Scotia Supreme Court held in *Pictou Landing First Nation v. Nova Scotia* that the duty to consult can be separately triggered when the Crown contemplates providing funding for a project that may adversely impact asserted or established Aboriginal rights. In this case, there was no dispute that there was a duty to consult for the environmental assessment being conducted for the project but the question was whether the Province's consideration of whether to provide provincial funding for the project engaged a separate duty to consult. While certain governments in Canada in practice consult when providing funding for projects that could adversely impact asserted or established rights, this is more frequently done in circumstances where the only Crown decision is a funding decision and the project would not be built unless the government funding is provided.

This case related to a proposal to construct a new effluent treatment facility at a bleached kraft pulp mill in Pictou County. The mill had an existing effluent treatment facility which had been operating since 1967 and is scheduled to cease operating on or before January 31, 2020. The project would replace this facility and the Province was already undertaking consultation with the First Nation for its decision on the related environmental assessment. The Court held that that it could not conclude that the project will not be built without provincial funding but that the funding would make it incrementally more likely for the mill to remain open and able to continue operations past 2020 and that if the Province provided funding it would “influence ‘higher level’ strategic decision making” relating to the project.

It is unclear how the Court determined that funding would “undoubtedly” influence the environmental assessment rather than the government’s review of the project influencing the funding decision. The Court also questions whether it would be compatible with the honour of the Crown to provide funding for the project against the strong opposition of the First Nation, even though the Crown could conceivably proceed with the project after adequate consultation notwithstanding this opposition.

As of December 20, 2018, the Nova Scotia government has not indicated whether it will appeal the decision. Regardless of whether it is appealed, this decision could have implications for Crown consultation practices relating to energy projects that receive government funding, even as a risk management practice.

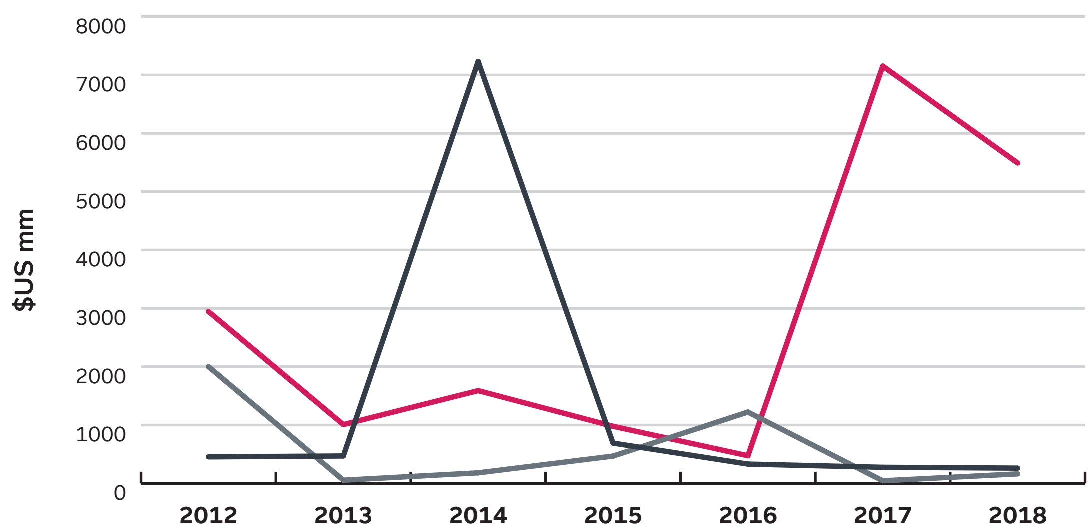
Mergers & Acquisitions

Authors: Suzanne Murphy, Kerri Lui, Scott Bergen, Maureen Gillis, and Chanelle Bristol

Introduction

2018 marked the continuation of strong domestic M&A activity for the Canadian power sector, with an aggregate domestic deal value of nearly US$5.5 billion. Investment in the Canadian power industry by non-Canadian companies has remained stagnant in 2018 with only three publicly reported deals — two from bidders in the United States and one from China — with a total value of US$425 million.

Canada M&A Deal Value in the Electricity, Power and Utilities Sectors



US Inbound	455	470	7,232	691	331	276	262
Non-US Inbound	2,001	55	181	468	1,228	45	163
Canada Domestic	2,946	1,008	1,590	979	474	7,152	5,491

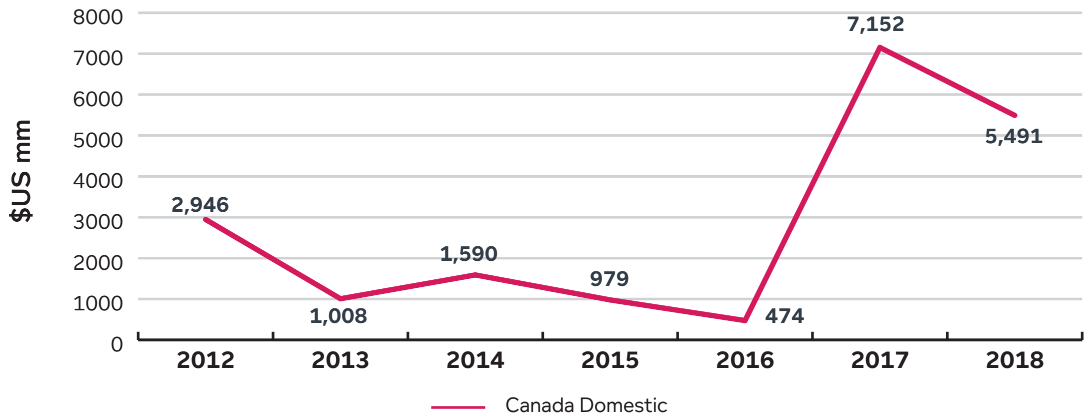
Source: MergerMarket

2018 was another active year for outbound investment in the power sector by Canadian companies in power projects with aggregate deal value of approximately US$28 billion (compared to US$36 billion in 2017). The most significant region for outbound investment in 2018 for Canadian companies was the United States, followed by the European Union, Latin America, Mexico and the Caribbean.

Investments by Canadians Domestically

Continuing some of the momentum from a surge in domestic investment in the power sector in 2017, 2018 was another active year for domestic deal activity.

Canada Domestic M&A Deal Value in The Electricity, Power and Utilities Sectors



Source: MergerMarket

The three major players in the Canadian power M&A market for 2018 (based on deal value) were Enbridge Inc., NextEra Energy Partners, LP and Canada Pension Plan Investment Board ("CPPIB").

In line with its announced intention to focus on expanding and growing its business in core markets and selling non-core assets following its merger with Spectra Energy, Enbridge Inc. was party to two major transactions in 2018. On May 9, 2018, Enbridge announced that it had agreed to sell 49% of its interest in select North American onshore renewable power assets and 49% of its interests in two German offshore wind projects (Hohe See, and related expansion) to CPPIB for US$1.35 billion. The North American assets included wind and solar assets in four Canadian markets and two operating assets in the United States. McCarthy Tétrault assisted Enbridge with Canadian due diligence matters on this transaction. Enbridge also agreed to dispose of Enbridge Gas New Brunswick Limited Partnership and Enbridge Gas New Brunswick Inc., the primary provider of natural gas distribution in New Brunswick, to Liberty Utilities (Canada) LP, a wholly owned subsidiary of Algonquin Power & Utilities Corporation, for US$251 million.

One of the other major transactions of 2018 was the disposition by NextEra Energy Partners, LP of its portfolio of wind and solar generation assets in Ontario to CPPIB for US$1.27 billion. McCarthy Tétrault represented NextEra on this transaction. This acquisition by CPPIB, coupled with its aforementioned acquisition from Enbridge, indicate that CPPIB is committed to making significant investments in wind and solar projects. This commitment may continue into 2019, as CPPIB has announced its intention to continue to seek opportunities to expand its power and renewables portfolio globally.

Other significant domestic transactions included:

AltaGas Ltd. sold 35% of its interests in Northwest Hydro Facilities to a joint venture controlled by Axium Infrastructure Inc. and Manulife Financial Corp. for C$922 million in spring 2018 and, in December, announced it would sell its remaining majority stake to the same joint venture for C$1.39 billion. McCarthy Tétrault acted for the purchaser's lender on this transaction.

BC Hydro, which held a one-third stake in the 490-MW Waneta Dam in southeastern British Columbia, exercised a right of first offer to purchase the remaining two-thirds interest in the project from Teck Resources for C$1.2 billion, in a transaction that sees BC Hydro lease the purchased two-thirds share back to Teck, superseding a deal between Teck and Fortis Inc.

Innergex Renewable Energy Inc. completed its acquisition of Alterra Power Corp. for aggregate consideration of C$1.1 billion, including assumed debt. McCarthy Tétrault acted for Innergex on this transaction.

Connor, Clark & Lunn Infrastructure entered into an agreement to acquire a majority interest in Bremner Trio Hydro Corp., which owns two construction-stage, run-of-river hydropower facilities aggregating approximately 50 MW, located near Harrison Lake in British Columbia, for undisclosed consideration. McCarthy Tétrault acted for Connor, Clark & Lunn Infrastructure on this transaction.

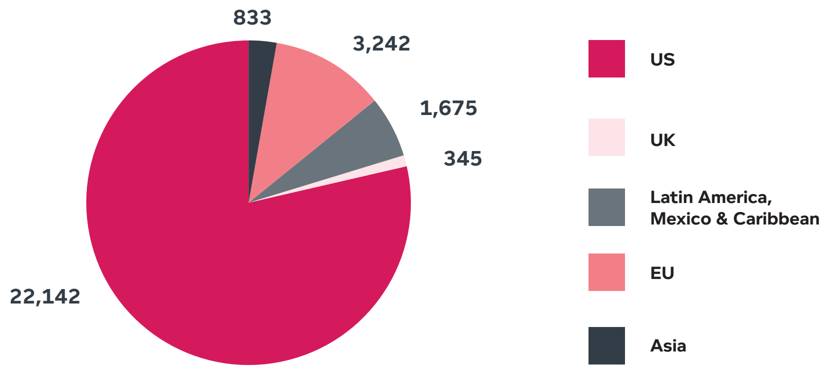
TransAlta Renewables Inc. acquired a number of projects from TransAlta Corporation, including the 20MW Kent Breeze Wind Farm in Ontario, for US$166 million.

A consortium of investors led by Axium Infrastructure Inc. agreed to acquire a minority interest in the K2 wind power facility in Ontario from Pattern Energy Group Inc. for US$166 million.

Foreign Investments by Canadians

In 2018, the majority of investment by Canadian companies in the power sector was in the United States, with a total investment by deal value of US$22.1 billion, followed by aggregate investment in the European Union in the amount of US$3.2 billion. This activity is consistent with the levels of investment into these jurisdictions in 2017. Notably, and in contrast with 2017, 2018 saw no investments by Canadian companies in the power sectors in Oceania and Africa and showed a decrease in investment in the United Kingdom and Asia.

Canada Outbound Investments in Electricity, Power and Utilities
($USmm)



Source: MergerMarket

The leading deals by value for Canadian companies investing in the power sector abroad in 2018 included the following transactions:

Enbridge Inc. and Spectra Energy Partners LP, a US–based company engaged in the transportation of natural gas through interstate pipeline systems and the storage of natural gas in underground facilities, agreed to convert all of the incentive distribution rights and general partner economic interests in Spectra held by Enbridge into 172,500,000 newly issued Spectra common units, valued at US$7.2 billion.

Alberta Investment Management Corporation agreed to acquire a majority stake in Eolia Renovables de Inversiones, S.C.R., S.A., a Spanish power producer, for US$1.5 billion.

Enbridge Inc. agreed to acquire all of the outstanding shares of Spectra Energy Partners LP for US$3.3 billion. McCarthy Tétrault acted as Enbridge's Canadian counsel on this transaction.

Canada Pension Plan Investment Board and Votorantim Energia Ltd. acquired a controlling stake in Companhia Energetica de Sao Paulo, a Brazilian hydro generation company, for US$1.2 billion.

Enbridge Inc. agreed to acquire all of the outstanding Class A common units and publicly listed shares of Enbridge Energy Partners, LP, a listed US–based energy company, for US$3.5 billion. McCarthy Tétrault acted as Enbridge's Canadian counsel on this transaction.

Superior Plus Corporation acquired NGL Propane, LLC, a US–based propane distribution company, for US$900 million.

Key Cases in 2018

Authors: Sam Rogers, Julie Parla, Andrew Kalamut, Samuel Lepage, and Jean Lortie

Alberta

There were significant developments in two major energy litigation matters in Alberta last year.

POWER PURCHASE AGREEMENT ("PPA") LITIGATION

The Power Purchase Agreement litigation came to an end via a settlement in 2018. This litigation had been commenced by the Province against certain buyers under Alberta's PPAs after a government agency had determined that Alberta's 2015 increase of the carbon levy paid by thermal generators of electricity (including for coal plants) was a "change in law" that permitted the buyers to terminate the PPAs, which had been losing money for the buyers. The settlement provided that the Province accept the termination of the PPAs, along with a transfer of carbon offset credits.

Interestingly, shortly after the settlement was announced, a defamation lawsuit was launched against the Province by a former Enron lawyer who the Province had tried to blame (in part) for the large losses suffered by the Province as a result of the termination of the PPAs.

LINE LOSS LITIGATION

In late 2017, the Alberta Utilities Commission ("AUC") released its "Phase 2 Module C" decision in the so-called "line loss" case. This very large and lengthy case concerns the calculation of transmission losses (losses of electricity that occur as it is being transmitted along transmission lines). This module, the last in a long series of such decisions, determined which methodology to use for determining loss factors. Due to the amounts at issue, the selection of the methodology has a significant financial impact on the parties involved.

Unsurprisingly, a number of parties are seeking to appeal the AUC's decision. Although there is no substantive decision yet, there was a decision concerning applications for party status by Balancing Pool and TransAlta (*Balancing Pool v ENMAX Energy Corporation*, 2018 ABCA 143). In the result, Balancing Pool was added and TransAlta was not (with permission to reapply if permission to appeal is ultimately granted). The Alberta Court of Appeal noted that there were currently twelve applications for permission to appeal brought by seven different parties with distinct grounds of appeal – highlighting the complex and sprawling nature of this litigation.

British Columbia

***HARRISON HYDRO PROJECT INC. V. BRITISH COLUMBIA (ENVIRONMENTAL APPEAL BOARD)*, 2018 BCCA 44**

This was an appeal of a decision summarized in our publication last year. The facts are brief but important: the limited partner owners of five "run of river" hydro projects near Harrison Lake, BC, sought judicial review of a decision of the Environmental Appeal Board, which held that the (single) general partner was the holder of the water licence issued under the *Water Act* for all five of the projects, and not the five limited partnerships. As a result of the EAB's decision, the "water rental rate" for each of the five projects was much higher than if the licences had been held by the limited partnership.

On judicial review, the BC Supreme Court held that the standard of review was reasonableness and that the EAB's decision was reasonable because the "EAB Decision accords with the above-noted statutory and common law principles concerning limited partnerships", which hold that limited partners must cede control of the business of a limited partnership to one or more general partners in order to receive the protection of limited liability.

Harrison Hydro appealed to the BC Court of Appeal, which dismissed the appeal in a 2-1 split decision. The majority held, like the judge below, that the EAB's decision was reasonable because it was "not inconsistent" with the legal principles regarding limited partnerships. The dissent would have allowed the appeal (and reversed the decision of the EAB) because the Board erred when it interpreted the phrase "substantial interest in land" in the *Water Act* as the definition adopted by the Board was too narrow and inconsistent with the context in which the phrase is used in the *Water Act*.

Harrison Hydro sought leave to appeal to the Supreme Court of Canada. That leave application was dismissed (2018 CanLII 71038) somewhat surprisingly given the split decision at the Court of Appeal.

Ontario

There were two interesting decisions last year concerning applications arising from or related to the now repealed *Green Energy Act*.

***ALLIANCE TO PROTECT PRINCE EDWARD COUNTY V. INDEPENDENT ELECTRICITY SYSTEM OPERATOR*, 2018 ONSC 4107**

This was a case that was foreshadowed in our publication last year. A local non-governmental organization ("APPEC") brought an application against the Independent Electricity System Operator ("IESO") for a declaration that that a FIT contract was null and void because the project did not comply with the contractual requirement to deliver 75% of the project's capacity. Had APPEC been successful, it would have called into question the validity of any FIT contract that had ever been amended. Happily for project owners, APPEC's application was dismissed.

The project at issue had a long history, as the application had been submitted by the proponent under FIT version 1.3, and the FIT contract had been awarded in May 2010. There were subsequent delays and then a lengthy regulatory approval process. The outcome of that regulatory approval process had required that the proponent and IESO agree to amendments to the FIT Contract to bring it in-line with the regulatory decisions.

APPEC argued that it had legitimate expectations that the FIT contract awarded to the proponent would be enforced, and not amended. APPEC also argued that the IESO had made negligent misrepresentations by publishing misleading or inaccurate information.

Both arguments were entirely rejected. **First**, the amendment of the contract undertaken by the proponent and the IESO was entirely appropriate and consistent with the language of the contract, and APPEC's complaints were complaints about substantive issues, which are something that the doctrine of legitimate expectations cannot address. **Second**, there was no misrepresentation as there was no "special relationship" between APPEC and the IESO, and, in any event, APPEC's purported reliance on representations in the FIT Contract was not reasonable and was based on an incorrect reading of the contract.

Finally, it should be noted that shortly after this decision was released, the government enacted the *White Pines Wind Project Termination Act*, 2018, which resulted in the cancellation of the FIT contract and decommissioning of the project in question in any event. A more detailed discussion of the White Pines Project can be found in our article on sovereign risk, which can be located on page 26 of this publication.

NATIONAL STEEL CAR LIMITED V. INDEPENDENT ELECTRICITY SYSTEM OPERATOR, 2018 ONSC 3845

The Ontario Superior Court of Justice struck two applications seeking to challenge a part of the "Global Adjustment". The Global Adjustment adjusts rates to cover the amounts paid by the IESO for procurement contracts. It has increased significantly since 2008 as a result of a number of factors, including the *Green Energy Act*. The applicant in these cases, National Steel Car Limited, had brought applications seeking declarations that portions of the Global Adjustment, primarily relating to FIT contracts, were unconstitutional as they amounted to a tax, which had not been authorized by the legislature (as the constitution requires).

The Court struck the applications at the pleading stage finding that it was "plain and obvious" that the applications had no chance of success because the Global Adjustment is a regulatory charge (and not a tax), and, in any event, it was enacted by the legislature so it was constitutional.

Had the applicant been successful, the result of this case would have been to shift the cost of FIT contracts from ratepayers to taxpayers. This would have had a significant impact on certain ratepayers, and it is noteworthy that, for the time being, the Global Adjustment appears to be safe from judicial interference.

Québec

There were three notable decisions in Québec last year.

MUNICIPALITÉ DE SAINT-ADOLPHE-D'HOWARD V. PROCUREUR GÉNÉRALE DU QUÉBEC (MINISTRE DU DÉVELOPPEMENT DURABLE, DE L'ENVIRONNEMENT ET DE LA LUTTE CONTRE LES CHANGEMENTS CLIMATIQUES), 2018 QCCS 78

In this decision, the plaintiff (a small city located in the Laurentians, a region north of Montréal) sought a provisional interlocutory injunction to stop the deforestation work conducted by Hydro-Québec on the plaintiff's territory in order to build a new power transmission line approved by the Environment Ministry.

The court denied the application on the ground that the conditions for issuing an interim interlocutory injunction order were not met. Indeed, the proceedings were initiated more than three months after the start of the deforestation work, which the court found was an unjustified delay. The court therefore concluded that the urgency alleged by the plaintiff resulted from its own inaction. Moreover, the plaintiff's allegations were not supported by the evidence. It seemed obvious to the court that the plaintiff was contesting the appropriateness of the Ministry's decision rather than its legality. The plaintiff failed to demonstrate the existence of a solid appearance of right, and the criteria of irreparable prejudice and the balance of convenience were not met.

McCarthy Tétrault successfully represented the respondent Hydro-Québec in this matter.

CHARLAND V. HYDRO-QUÉBEC, 2018 QCCS 2266

In Charland, the plaintiff initiated a class action against Hydro-Québec, in which she alleged that Hydro-Québec charged an illegal annual "interest fee", within the meaning of the *Interest Act*, of 14.4% to the class. This fee was charged to the customers who had not paid their hydro bill in time. According to section 4 of *Interest Act*, the annualized interest rate must appear on the invoice and the plaintiff therefore claimed the reimbursement to the class of the difference between the 5% prescribed in the act and the 14.4% actually charged. She also argued that, if section 4 of the *Interest Act* was applicable, the fact that the information on the annual rate was contained in an external document was in contravention with the conditions of that provision. For its part, Hydro-Québec maintained that the costs in question were an "administration fee", rather than interest, and argued that the proceedings and the questions submitted fell within the exclusive jurisdiction of the Régie de l'énergie.

The Superior Court agreed with Hydro-Québec's position and stated that the costs in question were not "interest fees" within the meaning of the *Interest Act*. The court also mentioned that even if the *Interest Act* was applicable, there would be no contravention of section 4 since the annual rate was indicated in the document "Electricity Rates", which was a component of the contract.

Finally, the court stated that although the Régie de l'énergie has the jurisdiction to set or modify Hydro-Québec's rates and billing terms and to monitor its activities, it does not have the exclusive jurisdiction to decide whether a fee charged by Hydro-Québec is in compliance with the Interest Act.

The plaintiff filed an appeal in November of 2018, and the appeal should be heard in 2019.

McCarthy Tétrault successfully represented Hydro-Québec in this matter.

GASTEM INC. V. MUNICIPALITÉ DE RISTIGOUCHE-PARTIE-SUD-EST, 2018 QCCS 779

In 2011, Gastem Inc. ("Gastem") undertook an oil exploration project and proceeded with the development of a drilling platform on the territory of the city of Restigouche in Gaspésie. The exploration and drilling activities were authorized by the Québec government. In March 2013, at the request of the city's residents, a municipal bylaw was adopted to protect water sources by prohibiting the use in the ground of any substance likely to affect water quality within a two-kilometre radius around any artesian or surface well.

The city found that Gastem's activities were in violation of its bylaw. In 2013, Gastem responded with a lawsuit seeking damages alleging that the city adopted the bylaw in an illegal, targeted and untimely manner in order to prevent Gastem from continuing its activities on the territory of the city. By way of a counterclaim, the city sought that Gastem's lawsuit be declared as abusive and be dismissed by the court, and claimed damages.

The court rejected Gastem's action and declared that the city had a duty to ensure the protection of the water sources on its territory in accordance with the applicable provincial regulations and statutes. According to the court, the bylaw was legal and the evidence presented at trial did not demonstrate that the city was acting in bad faith in adopting the bylaw. The court also concluded that Gastem's lawsuit was disproportionate and partially abusive and it ordered Gastem to pay damages to the city.

ABOUT McCARTHY TÉTRAULT'S NATIONAL POWER GROUP

Our Power Group consists of more than 30 lawyers nationally, including the most experienced energy lawyers in Canada. Our principal areas of practice include project development, project finance, mergers and acquisitions, utility restructuring, privatizations and procurement. We also have extensive expertise in advising and representing clients in the area of energy regulation and litigation.

Drawing on our breadth of expertise and experience in the power and energy sectors, we provide practical and timely advice to our clients, and take a hands-on approach to resolving issues. We understand the complexities associated with developing, structuring, financing, approving and operating a variety of different types of power projects.

Our retainers on North American electricity matters include acting for Canada's major public and private electric generators, transmission and distribution utilities, major equity investors and developers of power projects, lenders to power projects and fuel and equipment suppliers to the power industry.

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