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OUTLOOK SERIES 2021
Power Planning

Canadian Power

Key Developments in 2020
Trends to Watch for in 2021

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The **Power Group at McCarthy Tétrault LLP** is pleased to present: *Canadian Power – Key Developments in 2020 – Trends to Watch for in 2021*.

Message from our Editor-in Chief, Kerri Lui:
This publication is our sixth annual Canadian power industry retrospective. It is intended to provide an overview, at both the regional and national levels, of the most significant developments in the Canadian power sector in 2020, including in the areas of small modular reactors, hydrogen and energy storage, and to highlight key trends to watch for in 2021. We hope that you will find this publication to be both interesting and informative.

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British Columbia Regional Overview

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Introduction

2020 marked a year of unprecedented challenges for the BC power sector. The Province continued to review and assess the longer-term structure of its energy sector amid the immediate impacts of the COVID-19 pandemic, uncertainty regarding the Province's last large-scale hydroelectric project, and a surprise fall provincial election. With substantially all power procurement activities suspended indefinitely, independent power producers ("**IPPs**") and other industry participants await a number of key developments, including the completion by the provincial government of Phase 2 of its comprehensive review of BC Hydro, public consultations for the preparation of BC Hydro's long-awaited integrated resource plan, now due in late 2021, and the outcome of a review of the Site C hydroelectric project following concerns raised by BC Hydro regarding project risks, construction delays and rising costs. In the face of these developments, the provincial government continued to pursue its CleanBC climate strategy while facing criticism of its efforts to achieve related emission-reduction targets.

BC GOVERNMENT UPDATE

British Columbia's New Democratic Party ("**BC NDP**") started 2020 with a minority government and ended the year with a strong majority following BC NDP Premier John Horgan's controversial decision to call a snap election several months ahead of schedule in the fall of 2020 despite the ongoing COVID-19 pandemic. The gamble paid off, with the BC NDP winning 57 seats over the B.C. Liberal Party's 28 and the two seats retained by the B.C. Green Party ("**BC Greens**").

The election outcome ended the occasionally strained minority-government alliance between the BC NDP and the BC Greens, in place since 2017, just a few weeks after the BC Greens named Sonia Furstenau as the party's new leader, replacing Andrew Weaver. In the wake of the B.C. Liberals' weak results in the election, party leader Andrew Wilkinson resigned, setting the stage for a party leadership contest early in 2021.

Despite the change in the provincial balance of power, CleanBC remains a key component of the BC NDP's plans. Clean BC is British Columbia's ambitious climate action plan to reduce provincial greenhouse gas emissions to 40% below 2007 levels by 2030 and was launched in 2018 with significant input and pressure from the BC Greens. The 2021 annual mandate letter from

Premier Horgan to Minister Bruce Ralston, who leads B.C.'s newly renamed Ministry of Energy, Mines and Low-Carbon Innovation, foregrounds a number of CleanBC-focused initiatives, including, among others:

- **continued commitment to the CleanBC climate action plan focused on "building a low-carbon economy with new clean-energy jobs and opportunities", including as part of the Province's COVID-19 pandemic recovery plans;**
- **accelerating adoption of zero-emission vehicles with rebates, incentives for purchasing used electric vehicles and an expansion of the CleanBC Specialty-Use Vehicle Incentive program;**
- **establishing the B.C. Centre for Innovation and Clean Energy to drive innovations such as carbon capture and storage and renewable fuels;**
- **undertaking a review of oil and gas royalty credits to ensure they meet B.C.'s goals for economic development, a fair return on provincial resources and environmental protection; and**
- **working with industry, the federal government and BC Hydro to fast-track electrification across industry sectors for both large and small businesses.**

Despite this continued commitment, the provincial government faces ongoing criticism that it has not produced credible plans to achieve CleanBC's targets.

In December 2020, B.C. released its first annual Climate Change Accountability Report ("**CCA Report**") mandated under the *Climate Change Accountability Act* (British Columbia). Following its release, the B.C. Government acknowledged that the CCA Report confirms that finalizing the roadmap to CleanBC's ambitious emissions targets (which also include a 60% reduction in emissions over 2007 levels by 2040 and an 80% reduction by 2050) has been more challenging than anticipated.

The CCA Report indicates that greenhouse gas emissions ("**GHGs**") actually rose 3% in 2018 over the preceding year as a result of increased fuel consumption, particularly from heavy-duty trucks, oil and gas exploration, and off-road industrial transport. The Province reports that the apparent backslide is attributable in part to changes in the way the federal government requires marine GHGs to be reported, which reduced the 2007 baseline against which B.C.'s future reduction targets are to be measured.

Bright spots in the CCA Report included indications of strong uptake of light-duty electric vehicles in B.C.; nearly 9% of light-duty vehicles sold in B.C. in 2019 were zero-emission vehicles, almost meeting the Province's goal of 10% by 2025 (six years early). B.C. also saw a 55% increase in public fast-charging sites for electric vehicles over 2018. Meanwhile, reported fugitive and vented methane emissions in the upstream oil and gas sector decreased 11% between 2014 and 2019.

While acknowledging that its plan to reach its 2030 GHG reduction target is still in progress, the Province has set a new interim target of 16% below 2007 levels by 2025 for GHGs in B.C. The Province has also stated that it will set sectoral targets by March 31, 2021, and will develop legislation to ensure B.C. reaches net-zero emissions by 2050.

Despite calls to prohibit expansion of liquefied natural gas ("**LNG**") initiatives as a result of the CCA Report's findings, which commentators project would leave the Province with 2030 GHG emissions significantly above CleanBC's targets, the B.C. government has indicated it does not plan to do so as long as any proposed LNG expansion falls within CleanBC targets.

The pandemic has also posed challenges for the implementation of some of B.C.'s climate policy plans, with the Province delaying a scheduled April 2020 increase of B.C.'s carbon tax from $40 to $45 per tonne of carbon dioxide equivalent (tCO_2e) until April 2021. Meanwhile, the Province has doubled CleanBC retrofit rebates for certain home-heating and energy-efficiency upgrades in an effort to support B.C.'s economic recovery from the impact of COVID-19.

COMPREHENSIVE REVIEW OF BC HYDRO

The provincial government's Comprehensive Review of BC Hydro, initiated in 2018, remains ongoing. The Review is currently in its second phase, with a mandate to evaluate broad, transformational changes that are likely to impact the energy sector in coming years. The Phase 2 Final Report is expected to set out recommendations for how BC Hydro can accomplish the provincial policy objectives laid out in the CleanBC plan, as well as consider the impact of factors such as emerging technologies, energy market trends, and the changing needs of BC Hydro customers. Phase 2 of the Review is intended to support the development of BC Hydro's long-anticipated integrated resource plan ("**IRP**"), its first such plan since 2013.

The (since renamed) Ministry of Energy, Mines and Petroleum Resources released a high-level Phase 2 Interim Report (the "**Interim Report**") for comment in early March 2020, with a final report (the "**Final Report**") intended to follow within two months. The Interim Report pointed to a number of potential significant changes to BC Hydro. For example, it indicated that:

- it may be time to reconsider BC Hydro's current conservation-focused tiered rate structure, whereby ratepayers pay more for electricity over a certain amount of usage, in favour of optional rates designed to encourage use of the cleanest form of energy available and shape demand to capacity (for example, by implementing variable rates based on time of use for consumers and flattening the two-tier rate for industry);

- BC Hydro is looking at developing an internal carbon price for use in valuing its GHG reductions;

- an economic development rate for energy-intensive low-carbon industries and changes to BC Hydro's interconnection tariffs could reduce time and cost barriers to electrification of industry, particularly in the upstream oil and natural gas industry; and

- the self-sufficiency provision in the *Clean Energy Act* (B.C.), which restricts BC Hydro from purchasing energy from outside jurisdictions in favour of self-sufficiency even where clean and renewable resources in other jurisdictions may be more affordable, may be a source of undue constraint, and the Final Report will look at the impact of eliminating this restriction, opening the way for greater importation of energy.

Following the release of the Interim Report, however, the COVID-19 pandemic altered energy consumption and production in the Province, and both industry and other stakeholder groups commented during the feedback period that assumptions underpinning the Interim Report had been disrupted. Furthermore, a number of groups were critical of the discussion-paper format of the Interim Report and the lack of draft recommendations and policy details on which to comment.

> **The Final Report has not yet been released. Given the change in circumstances since the release of the Interim Report, it is probable that the Ministry will release a draft version of the Final Report for stakeholder feedback, though no timeline or information has been provided.**

The Comprehensive Review process is closely intertwined with the IRP process, which as noted below is currently engaged in ongoing consultations with the public and Indigenous groups, as well as technical consultations.

The B.C. Government has not waited for the Final Report to implement one measure hinted at in the Interim Report. On December 21, 2020, an Order of the Lieutenant Governor in Council of B.C. was issued directing the British Columbia Utilities Commission ("**BCUC**"), on application, to approve new CleanBC industrial electrification rates consisting of subsidized industrial energy rates for a fixed seven-year term, available to new customers and customers undertaking certain electrification projects, subject to certain limitations. The order also directs the BCUC, on application, to consent to the rescission of Tariff Supplement No. 37 – Northwest Transmission Line Supplemental Charge, a supplemental charge applicable to certain customers as a condition of BC Hydro providing electricity to the customer by means of the Northwest Transmission Line or providing generator interconnection service to the interconnection customer to enable delivery of its generating facility output by means of the Northwest Transmission Line, a 344-kilometre, 287-kilovolt transmission line that originates near Terrace, B.C. and that ends at a substation near Bob Quinn Lake in the northwestern part of the Province.

BC HYDRO INTEGRATED RESOURCE PLAN

As we noted in last year's publication, BC Hydro was expected to release its integrated resource plan, the utility's 20-year projection of electricity demand and its plan to meet this need, in February 2021. Due in part to COVID-19 impacting BC Hydro's workload and consultation process, filing of the IRP has been further delayed. In July 2020, the BCUC ordered BC Hydro to conduct public consultations in connection with the IRP, noting that the last time it reviewed BC Hydro's long-term planning forecast was in 2010 (BC Hydro's subsequent 2013 IRP was exempted from BCUC review), and that the lack of a more recent plan impedes the BCUC's ability to efficiently discharge its regulatory responsibilities in relation to the review of BC Hydro and related regulatory applications (including in relation to the renewal of electricity purchase agreements ("**EPAs**"), as discussed below). Following this, BC Hydro confirmed that the IRP would be filed September 2021 following consultations with Indigenous nations, a newly established Technical Advisory Committee, and both customers and the broader public.

BC HYDRO RATE APPLICATION

On October 2, 2020, the BCUC issued its final decision on BC Hydro's fiscal 2020 and fiscal 2021 revenue requirements application ("**RRA**"). As part of the RRA, the BCUC found BC Hydro's forecast revenue requirement to be reasonable with the exception of certain items identified in the decision, and approved BC Hydro's application for a permanent reduction from 5% to 0% of the Deferral Account Rate Rider, a surcharge on ratepayers' bills used to pay down BC Hydro's energy deferral accounts.

The BCUC also directed BC Hydro to file its fiscal 2022 RRA by December 2020, for expedited review. Provided there are no delays, it is expected the BCUC will issue its final decision in summer 2021. This expedited review of BC Hydro's RRA is intended to align with BC Hydro's next multi-year RRA timing.

EPA RENEWALS

The BCUC has underscored in recent decisions that it is unable to determine whether long-term EPA renewals are in the public interest until BC Hydro files a new IRP. Accordingly, applications for EPA renewals in 2020 have generally been limited to three-year renewal terms.

As we noted in last year's publication, BC Hydro filed applications to renew three EPAs entered in respect of hydroelectric projects—Sechelt Creek Hydro, Brown Lake Hydro and Walden North Hydro—to extend the terms by 40 years. The BCUC adjourned the proceeding to allow BC Hydro and the counterparties to restructure and resubmit the EPA renewals (not to exceed three years) to allow BC Hydro to complete its IRP. In February 2020, BC Hydro resubmitted the EPA renewals with three-year terms in respect of Sechelt Creek Hydro and Brown Lake Hydro, which were accepted for filing.

However, BC Hydro issued a notice of termination for the EPA renewal in respect of Walden North Hydro, relying instead on its original EPA and related forbearance agreement (the "**Forbearance Agreement**") whereby BC Hydro agreed to forebear its right to terminate the original EPA in exchange for compensation from the IPP.

In response, the BCUC requested submissions on the Forbearance Agreement, which had never been filed with the BCUC, and concluded that it constituted an amendment to the original EPA required to be filed with the BCUC under section 71 of the *Utilities Commission Act* (the "**UCA**"). The BCUC also directed BC Hydro to, among other things, file all unfiled agreements associated with and materially affecting any other existing EPAs as separate amending agreements.

BC HYDRO FORCE MAJEURE CLAIMS

In early May 2020, BC Hydro announced that it would reduce purchases of power under certain EPAs with IPPs, citing the COVID-19 pandemic, and related governmental measures in response to it as constituting a force majeure event under the terms of the applicable EPAs. While the number of EPAs under which BC Hydro declared force majeure was not publicly released by BC Hydro, a press release from at least one IPP stated that BC Hydro delivered notices temporarily halting the purchase of power from May to July under at least six EPAs.

BC Hydro's standard EPA terms include confidentiality and arbitration provisions, so additional public information regarding the force majeure claims is unlikely to become available unless released by BC Hydro or as part of the disclosure requirements of any affected IPP that is a public company.

In conjunction with the delivery of the force majeure notices, BC Hydro issued a report titled "Demand Dilemma: How BC Hydro is responding to declining load and operational challenges resulting from COVID-19", in which BC Hydro provided an overview of the declining load and operational challenges it faced due to the COVID-19 pandemic, attempting to support its claim that it was necessary to invoke force majeure under the EPAs. In particular, BC Hydro noted that:

as a result of the pandemic's significant impact on the provincial, national and global economies, it estimated at that time that electricity demand in British Columbia had been reduced by nearly 10%;

with uncertainty around the speed of British Columbia's economic recovery, it estimated electricity demand could decrease by 12% or more by April 2021; and

at that time of year, BC Hydro was experiencing significant inflows from the spring freshet (snowmelt), increasing capacity at its larger reservoirs, and potentially leading to large and prolonged spills from its facilities that could have adverse environmental effects.

In addition to invoking force majeure under its EPAs, BC Hydro noted that other measures being taken to reduce environmental risks arising from increased spillage at its facilities as a result of reduced load included shutting down operations at certain of its smaller plants to reduce generation and increasing the export of electricity to other jurisdictions through its trading subsidiary, Powerex.

At least one IPP has publicly disclosed its intention to dispute BC Hydro's force majeure claim, noting that while BC Hydro retains "turn-down" rights under its EPAs that enable it to require the operator to turn down or shut off its facilities in certain circumstances, including in order to avoid a safety or stability risk, BC Hydro is required to compensate the operator for energy that would have been produced at the facilities in the absence of the curtailment.

In September 2020, BC Hydro released a subsequent report, titled "Powering through uncertainty: Shifting habits since COVID-19 restrictions were eased and what that means for future electricity demand in B.C.", in which it provided updated data with respect to power consumption and forecast load growth following the Province's economic restart after the first wave of the COVID-19 pandemic.

> **BC Hydro's results showed that with more British Columbians back at work and spending less time at home, provincial electricity use steadily increased from mid-June as many businesses reopened, with overall demand in August increasing to 7% below BC Hydro's pre-COVID-19 load forecast.**

BC Hydro stated that while overall electricity load is expected to remain lower than previously forecast over the next one to two years, it is expected to rebound in the long term due to population growth, fuel switching and the electrification of transportation, home heating, and industries that are dependent on fossil fuels.

SITE C PROJECT UPDATE

The COVID-19 pandemic significantly impacted progress on the 1,100 MW Site C project on the Peace River in northeastern B.C. On March 18, 2020, BC Hydro announced that work would be scaled back in response to the pandemic. Essential services and work critical to achieving river diversion were prioritized. In May 2020, construction activities at the site began to gradually increase. The most recently released employment figures show that the project employed 5,181 people in October 2020, approximately 72% of whom were workers from B.C. The diversion of the Peace River, an important project milestone, was completed in October 2020. However, the COVID-19 pandemic continues to add uncertainty to the remainder of the project schedule, and BC Hydro has not yet confirmed its impact on the previous target in-service date for the project of November 2024. On December 29, 2020, B.C.'s public health officer issued a new order limiting the number of workers on site at the project.

In addition to challenges posed by the COVID-19 pandemic, the Site C project is also grappling with previously identified geological risks requiring foundational enhancements to increase stability under core areas of the right bank of the Peace River. BC Hydro continues to work with the independent Site C Technical Advisory Board and the Project Assurance Board to determine appropriate enhancement measures. The impact on cost and schedule is anticipated to be more substantial than initially expected and will be better understood once enhancement measures are finalized.

In July 2020, B.C.'s energy minister appointed former deputy finance minister Peter Milburn as a special advisor to conduct an independent review of the Site C project after BC Hydro reported the above concerns about project risks, construction delays and rising project costs. His report is expected to be discussed with cabinet and made public in the first quarter of 2021. More recently, the B.C. Government announced that it has also commissioned two dam-safety experts to review BC Hydro's proposed solution to the project's geotechnical problems.

In an ongoing civil action, West Moberly First Nations allege that the Site C project unjustifiably infringes their Treaty 8 rights. In a parallel civil action, Prophet River First Nation similarly alleged infringement of its Treaty 8 rights. In 2019, the B.C. Government, BC Hydro, West Moberly and Prophet River entered into confidential discussions to seek alternatives to litigation. In August 2019, West Moberly withdrew from such discussions and expanded their original action to focus on the cumulative impacts of all three Peace River facilities, not just the Site C project. West Moberly are seeking an injunction against operating the Site C dam, an order to remove the dam, and damages, including the payment of all revenues earned on the existing Peace River dams. The trial is expected to occur in 2022. In August 2020, Prophet River reached two agreements with the Province of British Columbia and BC Hydro regarding, among other things, land management and naming rights that resulted in the discontinuation of its civil action.

LNG UPDATE

The natural gas tax credit announced in March 2019 to encourage development of the LNG industry in B.C. went into effect on January 1, 2020. This credit can reduce the applicable corporate tax rate from 12% to 9% for qualifying corporations.

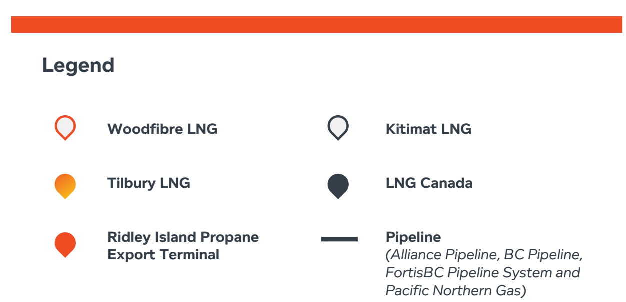
LNG Canada – a joint venture between Shell Canada, PETRONAS, PetroChina, Mitsubishi Corporation, and KOGAS and the only active LNG project in B.C. – continues construction of its LNG facility in Kitimat, B.C. Despite delays caused by the COVID-19 pandemic, major work is underway, including site preparation, dredging, and construction of a marine terminal. In 2020, the first group of residents moved in to Cedar Valley Lodge, LNG Canada's long-term workforce accommodation centre and facilities, which will provide accommodation for up to 4,500 workers. LNG Canada is now targeting a 2025 completion date. When constructed, LNG Canada's $40 billion facility will consist of two trains with a total capacity to produce 14 million tonnes of LNG per year.

Data Source: B.C. Government

In May 2020, TC Energy (formerly TransCanada Corporation) announced it had completed the sale of a 65% equity interest in the 670 km Coastal GasLink Pipeline to private equity firm KKR and Alberta Investment Management Corporation. The first segments of this project were laid in the ground in July 2020 following high-profile protests in February in support of the Wet'suwet'en hereditary chiefs, whose traditional territories are crossed by the pipeline. These protests have temporarily ceased under the terms of a memorandum of understanding between the hereditary leadership and the provincial and federal governments. For now, construction of the pipeline continues and, when complete, it will deliver natural gas from the area near Dawson Creek, B.C. to LNG Canada. It will be built to carry 2.1 billion cubic feet per day, with the potential for expansion to carry up to 5 billion cubic feet per day.

In December 2019, Chevron Canada announced its intention to exit its investment in Kitimat LNG, a 50/50 joint venture between Chevron Canada and Woodside Energy that includes a natural gas liquefaction facility at Bish Cove near Kitimat, upstream resources in the Liard and Horn River Basins in northeast British Columbia, and the proposed 480 km Pacific Trail Pipeline. However, Chevron Canada has not yet sold its 50% stake in Kitimat LNG. In February 2020, Woodside Energy announced it was reducing the book value of Kitimat LNG by $1 billion due to uncertainty in the timing of the development of its Liard natural gas fields. When complete, the Kitimat LNG plant would include three LNG trains with a capacity of 18 million tonnes per year and be powered entirely by electricity.

Tilbury LNG, located in Delta, B.C., and owned and operated by FortisBC, continued its Phase 1 expansion and has proposed a Phase 2 expansion. The Phase 1 expansion would bring Tilbury LNG's liquefaction capacity to up to 0.65 million tonnes of LNG per year, and is expected to be complete in 2023.



The $3 billion Phase 2 expansion, if approved and constructed, will increase the liquefaction capacity to 3.5 million tonnes per year by 2026.

The Woodfibre LNG project, located near Squamish, B.C., has been delayed due to the COVID-19 pandemic and a restructuring of McDermott, the project's main engineering, procurement, and construction contractor. The BC Environmental Assessment Office has granted the project a five-year extension on its environmental approval certificate. Project owner Pacific Oil and Gas Ltd. is now expected to formally approve the project by the third quarter of 2021, with construction to begin shortly thereafter and the production of LNG for export to start by late 2025. When complete, the project will have a production capacity of 2.1 million tonnes per year.

Another major proposed LNG production facility near Kitimat is Cedar LNG. This project, sponsored and proposed by the Haisla Nation, is expected to cost between $1.8 and $2.5 billion and would be one of North America's first-ever floating LNG terminals. Phase 1 of the project is currently planned for 2022, with operations planned to commence in 2025. When complete, the project would be capable of producing up to 6.4 million tonnes of LNG per year. Like LNG Canada, Cedar LNG plans to receive gas from the Coastal GasLink pipeline. Cedar LNG has already received an export licence from the Canada Energy Regulator, and in January 2020 the federal Minister of Environment and Climate Change approved the Government of British Columbia's request to substitute British Columbia's environmental review process for the federal impact assessment process. With the provincial environmental assessment process underway, the Haisla Nation approved two partners for the project in November 2020: Pacific Traverse Energy and Delfin Midstream.

Two other major LNG pipeline projects, Enbridge's Westcoast Connector Gas Transmission project and TC Energy's Prince Rupert Gas Transmission project, have obtained the primary regulatory approvals necessary in order for the projects to proceed.

Both pipelines would deliver gas from northeast B.C. to LNG facilities in the Prince Rupert area. While the initial LNG projects to be served by these pipelines are not proceeding, Enbridge and TC Energy continue to evaluate alternatives for the pipelines.

What to Expect in 2021

COMPLETION OF BC HYDRO REVIEW

As noted above, the Phase 2 Final Report is expected to be released in draft form for stakeholder feedback, following which it is expected to be finalized within a timeframe that permits it to inform BC Hydro's preparation of the IRP before the latter is submitted to the BCUC in September 2021.

AT LAST: 2021 INTEGRATED RESOURCE PLAN

After numerous delays, BC Hydro's long-overdue integrated resource plan (last prepared in 2013) will finally be submitted in late 2021. The IRP planning process was disrupted by the COVID-19 pandemic but is proceeding and will be informed by the outcome of Phase 2 of the BC Hydro comprehensive review, the Province's CleanBC energy roadmap, and BCUC-mandated public consultations.

As we noted last year, there are a number of forces that could materially reshape the load-resource balance in the Province, including the large-scale electrification called for under the CleanBC, the potential for additional LNG-related load and potential shortfalls in the achievement of BC Hydro's demand-side management initiatives. To these must be added the remote but still real possibility that the Site C project is cancelled in the face of mounting safety and cost issues, which would instantly transform the Province's load-resource landscape.

SITE C: POINT OF NO RETURN?

The release of the Milburn Report by the B.C. provincial government, expected in the first quarter of 2021, along with the findings of recently commissioned safety experts, will be critical to assessing the projected cost and ultimate fate of the Site C hydroelectric project. An independent analysis by the C.D. Howe Institute in January 2019 concluded that the project may only be "marginally economic" based on its current projected budget of $10.7 billion, and that any meaningful further cost increases would make cancellation of the project a better choice.

LONG-TERM EPA RENEWALS: STILL ON HOLD

Given the BCUC's decision that it is unable to determine that long-term EPA renewals are in the public interest until updated information is available on BC Hydro's energy needs and supply alternatives, the fate of long-term EPA renewals continues to be in limbo until the IRP is finally submitted later this year.

Alberta Regional Overview

Authors: Jamie Gibb, Kerri Howard, Kimberly Howard and Ashley Wilson

Introduction & Market Update

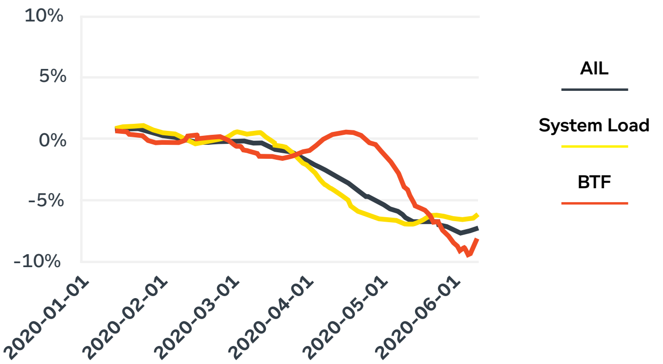
Over the past year, Alberta's energy industry has continued to be the central focus for the Province with an emphasis on innovation and diversification. In 2020, Canada faced the largest public health crisis in a century, the worst global economic crisis since the 1930s and a crippling collapse in energy prices. In response to the downturn, the Government of Alberta released a Recovery Plan in June 2020. The Province committed to diversifying Alberta's energy industry through a number of strategies and regulations which include: (i) Alberta's Natural Gas Vision and Strategy which lays out a plan for the Province to become a global supplier of clean, responsibly sourced natural gas, which includes the supply of hydrogen; (ii) a new mineral strategy to optimize Alberta's resource potential, including lithium; and (iii) the introduction of Bill 36, the *Geothermal Resource Development Act*, to establish a regulatory scheme for the development of geothermal resources.

Alberta's generation mix is expected to undergo a major shift as federal and provincial policies drive the retirement of all coal-fired generation by 2030. The Alberta Electric System Operator ("**AESO**") forecasts that coal will be replaced with a mix of natural gas generation and renewable energy. Alberta's merchant power market presents a unique opportunity for innovation and investment in clean energy in the Province through its many features, including the carbon market, power purchase agreements and government incentives targeted at moving toward a greener and diversified economy.

Throughout 2020, the ongoing effects of COVID-19 and low oil prices caused significant disruption to Alberta's electricity industry and the economy more broadly. The AESO indicates that load at behind-the-fence ("**BTF**") industrial sites, which are primarily oil and gas related facilities, began to decline due to persistently low oil prices, and in August, Alberta Internal Load ("**AIL**") hit its lowest levels at 950 MW, 10% below weather adjusted normal. According to the Market Surveillance Administrator ("**MSA**"), 2020 had the highest amount of supply surplus of any year in the last 20 years. Q3 2020 observed 1,865 minutes of supply surplus; the previous high was 231 minutes in Q3 2012.

30-day Rolling Average Change

Change in Capital "Actuals" vs Normals (%)



Source: AESO, Impact of COVID-19 and Low Oil Prices on Alberta's Power System (June 29, 2020)

Key Developments in 2020

ALBERTA'S ENERGY STORAGE ROADMAP

With respect to energy storage, Alberta is a flurry of activity. Alberta's first transmission connected energy storage project was completed in September 2020, and there are 10 additional energy storage projects within Alberta's connection queue.

In August 2019, the AESO released its Energy Storage Roadmap setting out a plan to facilitate the integration of energy storage technologies into the AESO's Authoritative Documents and the AESO's grid and electricity market. Highlights of the regulatory initiatives undertaken in 2020 to implement energy storage into Alberta's grid are discussed in detail in our storage article at page 69 of this publication.

DISTRIBUTION SYSTEM INQUIRY

The Alberta Utilities Commission ("**AUC**") launched the Distribution System Inquiry ("**DSI**") in December 2018 to provide a forum for Alberta's electricity industry to consider a regulatory response to mounting economic and technological pressures affecting Alberta's electric distribution systems. The inquiry was comprised of three modules, collectively focused on understanding three key questions:

- How will new technologies affect the grid and existing electric distribution facility owners and how quickly?
- How will incumbent electric distribution utilities be expected to respond to alternative approaches to providing electrical services, and which of these services should be subject to regulation?
- How should electric distribution facility rate structures be modified to incentivize efficient and cost-effective use of the grid?

The AUC identified certain emerging trends and innovations in Module One, which concluded on November 15, 2019.

> **Notably, the AUC found that there was greater customer choice and control over electricity consumption, and Alberta's electricity market had become more competitive.**

Modules Two and Three both concluded on July 15, 2020. Module Two examined the interplay between the trends identified in Module One and certain forces affecting existing distribution utilities: changing consumer preferences, service prices, taxes, subsidies and government incentives aimed at consumer behavior. The resulting discussion included which distribution utility services ought to be regulated, the related implications for the monopoly franchise and the obligations to serve, and to what extent (if any) new entrants should be regulated by the AUC.

Module Three examined the ability of current rate designs to encourage investment in distribution systems and deter uneconomic bypass of regulated facilities.

The considerations included:

- What information from regulated utilities should be made available to new entrants for the purposes of interconnection, physical co-location of facilities, and unbundling of or equal access to facilities?

- Should information from new entrants be made available to other market participants, and if yes, on what terms?

- What process should the AUC follow to consider regulatory changes meant to deal with the issues identified by the DSI?

The DSI was conducted by way of a series of information requests and written submissions. The final DSI report, which has yet to be published, is expected to set out a regulatory framework intending to facilitate efficient outcomes in Alberta's utilities market.

ISO TARIFF – DISTRIBUTED CONNECTED GENERATION ("DCG") CREDITS

DCG reduces strain on the system by displacing power that would otherwise have to be imported by distribution facility owners ("**DFOs**") from the transmission system. DCG reduces congestion, lowers line losses and enhances system reliability by having generation located closer to consumers.

Several DFOs' tariffs give a transmission-based credit to large-scale DCG providers for the electrical energy they supply to the distribution system.

The credits are calculated by determining the difference between the AESO system access service charges to a DFO with a distributed generator in operation and the charges that would have been incurred had the distributed generator not been in operation. The idea is to encourage DCG by providing a credit for the reduced amount of electricity a DFO draws from the power pool when a distributed generator interconnects with its wires.

The future of DCG credits has been uncertain since the AUC's 2018 ISO Tariff Decision issued on September 22, 2019. In this proceeding, the AUC noted evidence of a cross-subsidy resulting from DFOs being required to provide credits to DCG providers but not receiving any corresponding benefit. DFOs recover the cost of DCG credits by passing transmission costs on to load customers, meaning that, in effect, load customers are forced to subsidize the cost of DCG.

The DSI more recently contemplated the following key submissions regarding DCG credits:

The cross-subsidy between generators with DCG and those without results in an unlevel playing field in the energy market.

The market conditions leading to the creation of DCG credits have changed and their original intended benefit is no longer being accomplished.

DCG credits should be transformed into a mechanism that determines locational value, compensating according to value creation and development.

In early March 2021, the AUC is set to hear AUC Proceeding 26090 which will consider whether DCG credits shall continue to be implemented in a distribution utility's tariff. Currently, through their respective utility tariffs, each of FortisAlberta Inc., ATCO Electric Ltd. and ENMAX Power Corporation offer DCG credits. The AUC intends to decide this matter for all distribution tariffs and the AUC currently anticipates its determination in this proceeding will affect each of ATCO Electric, ENMAX and FortisAlberta as well as their customers, and the owners and operators of DCG units that receive benefit from DCG credit mechanisms.

DCG credits do not operate in a vacuum - they are intertwined with a number of other tariff, transmission and distribution system planning issues. It is within the context of these broader policy considerations that the fate of DCG credits will be determined. The future of DCG credits will likely be borne through the result of regulatory and distribution tariff proceedings, such as AUC Proceeding 26090, and the industry and market participants can likely expect the final DSI report to provide a regulatory framework which is intended to achieve competitive market outcomes.

CHANGES TO ADJUSTED METERING PRACTICE AND SUBSTATION FRACTION METHODOLOGY

Following the AUC's Decision 25848-D01-2020 (the "**Decision**") in late December 2020 varying Decision 2294-D02-2019, lenders and project developers within Alberta can expect impacts to connection costs for DCG projects. The Decision approved the AESO proposed adjusted metering practice and use of the substation fraction methodology to allocate the costs of interconnection facilities that may have joint use as part of the 2018 independent system operator ("**ISO**") tariff.

Highlights of the material findings and outcomes include:

- The AUC approved the AESO's proposed substation fraction methodology of one ("**SSF=1**") at all DFO contracted substations on a prospective basis which will attribute all connection costs to Rate Demand Transmission Service ("**Rate DTS**") contracts and none to Rate Supply Transmission Service ("**Rate STS**") contracts.

- The AUC confirmed that incremental costs which result from the connection of the DCG to the distribution or transmission system or alteration of connection facilities should flow through to DCGs. In order to adequately and accurately allocate incremental connection costs of the transmission system to DCGs that caused those costs, in all future customer contribution decisions ("**CCDs**"), the AESO was directed to clearly identify the DCG incremental transmission connection costs.

- Past CCD recalculations may have allocated costs to a DCG which did not reflect the actual incremental costs associated with their connection to DFO-contracted substations. In response, the AESO is directed to (i) reallocate such additional costs from the Rate STS to the Rate DTS, and (ii) recalculate CCDs using the SSF=1 methodology, in each case retroactively back to December 1, 2015, and inform the DFOs of those recalculations. The DFOs are directed to file a report with the AUC by March 31, 2021, with the details of the resolution of any such disputes with such DCGs. In future CCDs, the AESO will be responsible for clearly identifying, to the extent possible, the DCG incremental transmission connection costs.

- A new adjusted metering practice changing the point of totalization from the high side of a substation to the feeder level and impacting DCG credits and Rate STS contract capacities was approved by the AUC. The AUC determined this adjusted metering practice proposed by the AESO should be implemented without grandfathering and directed the AESO to submit revised tariff language as part of its compliance filing and implementation details in its next phase 2 tariff application.

- The AUC acknowledged that the adjusted metering practice will affect the availability of metering information currently used for the calculation of DCG credits. However, the AUC determined the issue with respect to the continuation of DCG credits is a distribution tariff matter and will be dealt with in AUC Proceeding 26090. AUC Proceeding 26090 will consider whether DCG credits should continue to be included in a DFO's tariff. AUC Proceeding 26090 is currently expected to be heard by the AUC during the second week of March 2021.

Noteworthy, and what will likely be carried forward to future decisions considering cost allocations, is the AUC's confirmation of the principle (established in AUC Proceeding 25101) that following energization, costs should not be allocated to a DCG if the DCG has not directly caused those costs. In other words, costs should be borne by the party benefitting from the connection project.The full effects and impacts of the Decision will be understood in the coming months.

The AESO's required compliance filing to effect the Decision was filed on January 11, 2021. DFOs must file reports by March 31, 2021, setting out the details of all resolutions and outstanding disputes pertaining to DCG flow-through matters.

SELF-SUPPLY AND EXPORT

In fall 2019, on behalf of the Alberta Department of Energy, the AUC issued Bulletin 2019-16 launching consultation on the issue of power plant self-supply and export. In the first round, the AUC sought stakeholder input on the following options for addressing the self-supply and export issue in the future:

Option 1: Status quo

Option 2: Limited self-supply and export

Option 3: Unlimited self-supply and export

In the second round of engagement, the AUC asked stakeholders to provide comments on the market and tariff implications of unlimited power plant self-supply and export.

On June 5, 2020 the AUC provided the Department of Energy with a discussion paper which summarized the views of market participants on how best to address the issue of power plant self-supply and export going forward.

The feedback received by the AUC was that most stakeholders do not oppose unlimited self-supply and export and generally agree that accommodating unlimited self-supply and export while preserving a fair, efficient and openly competitive market requires appropriate, tariff-based incentives. However, stakeholders disagreed on whether existing transmission and distribution tariffs provide the correct incentives to accommodate unlimited self-supply and export. A majority of stakeholders recognized that these issues will be more fully canvassed in the AUC's DSI and the upcoming AESO tariff proceeding.

The discussion paper recommends that regardless of which option the Province decides to implement, the statutory scheme should be amended to clarify the circumstances in which self-supply and export is expressly permitted to ensure regulatory certainty for stakeholders. Before the AUC can effectively address the tariff issue, the Department of Energy must decide, from a policy perspective, whether it wishes to allow self-supplying generators that do not otherwise qualify as an industrial system designation ("**ISD**") to self-supply and export.

Until the Department of Energy provides further direction, uncertainty remains for co-generation and industrial systems across the Province. It is anticipated that relief in the form of statutory amendments or new AUC rules may be on the horizon in 2021.

MARKET RULE DEVELOPMENTS

ISO Rule Amendments

The following are material or substantial new or amended ISO rules established in 2020:

ISO Rule 505.2 Performance Criteria for Refund of Generating Unit Owner's Contribution

Rule 505.2 was amended to clarify "generating facility" as a "generating unit or aggregated generating facility"; and its applicability to a solar aggregated generating facility.

*ISO Rule 306.7 Mothball Outage Rule (the "**Mothball Rule**")*

The AESO's Mothball Rule allows generators to take mothball outages. The Mothball Rule sets out how and when generators report temporary closures of generating facilities (5 MW or greater) for periods of up to two years.

On March 16, 2018, the MSA filed a complaint about the AESO's Mothball Rule, which was withdrawn following an amendment to the rule by the AESO.

Interveners in the MSA's complaint in support of the Mothball Rule submitted that: (i) generators must be able to rely on stable market rules permitting them to manage the operation of their assets; and (ii) generators should, in the context of a deregulated market, have the right to manage their assets in an economic, business-like and commercially effective way. Many generators rely on the Mothball Rule to operate their business efficiently. Generally, the position of these interveners was that the Mothball Rule supports the principles of fairness, efficiency and open competition that underpins the Alberta electricity market.

Interveners not in support of the Mothball Rule raised concerns about the addition of renewable generation and the early retirement of coal-fired generating units being the result of regulatory actions rather than market signals. These actions will impact supply/demand balances, and the investment price signal for retirements and generator additions. A high fidelity price signal is necessary to ensure that rational business decisions can be made and that sufficient power generation can be constructed in Alberta to meet future demand. This signal is necessary to ensure an efficient mix of technology and individual capacity is added to the generation fleet to support the growth of intermittent renewables and the replacement of Alberta's retiring baseload coal capacity.

In Q3 2020 the AESO reinitiated its review of the Mothball Rule to address stakeholder concerns raised in past consultations and to determine whether revisions to the Mothball Rule are required. The AESO intends to complete its regulatory review by Q4 2021.

AUC Rule Amendments

The following are material, substantial, new or amended AUC requirements or processes established in 2020:

Rule 027: Specified Penalties for Contravention of Reliability Standards

The AUC amended Rule 027, with an effective date of June 1, 2020. The changes incorporate all currently applicable Alberta reliability standards under classifications listed in the Rule 027 penalty table.

On October 21, 2020, the AUC subsequently amended Rule 027. The previous version of Rule 027 required the MSA to publish all notices of specified penalties issued for contraventions of reliability standards, including those related to CIP. It also required the MSA to post whether penalties had been paid or whether a notice of specified penalty is disputed, and in the latter circumstances, to post a link to the resulting AUC decision relating to such dispute. This amendment to Rule 027 exempts the MSA from making public any notice of specified penalties related to contraventions of CIP reliability standards including any related documentation.

Amendments to AUC Rules to Reduce Regulatory Burdens and Improve Efficiency

In June 2020, the Province introduced the *Red Tape Reduction Implementation Act* to reduce regulatory burdens and improve regulatory efficiency. The AUC forms part of this commitment to review its rules in order to reduce regulatory requirements. In November 2020, the AUC initiated a rule-review process which sought feedback from stakeholders on changes to *Rule 002: Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors, Rule 003: Service Quality Reporting for Energy Service Providers, Rule 021: Settlement System Code Rules* and *Rule 028: Natural Gas System Settlement Code Rules*. The proposed changes focused on the removal of unnecessary requirements, streamlining and updating filing requirements, and the improvement of administrative efficiency. The AUC approved the amendments to Rule 002, Rule 003, Rule 021 and Rule 028 with an effective date of December 17, 2020.

AUC Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments

Following stakeholder consultation, on August 7, 2020, the AUC released a revised draft version of *Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*. Feedback was sought to address emerging technologies and to eliminate duplication, clarify existing requirements and to make the rule easier to understand and to use. The Commission conducted a separate consultation process for developing Indigenous consultation processes and procedures. This is outlined further below.

The draft Rule 007 has been reorganized and includes separate categories for wind power plants, solar power plants and thermal power plants, hydroelectric power plants, "other" power plants greater than 10 MW, and community generation.

The draft version of Rule 007 includes new requirements to address the following:

- **End-of-life management for renewable energy operations** – the draft Rule 007 requires applicants to: (i) submit a copy of the renewable energy operations conservation and reclamation plan prepared in accordance with the *Conservation and Reclamation Directive for Renewable Energy Operations*; and (ii) a plan for how the operator intends to ensure sufficient funds will be available at the end of the project to cover the costs of decommissioning and reclamation activities.
- **Emergency response plan** – applicants must provide an emergency response plan that identifies any site specific risks, mitigation measures that may be implemented and appropriate site monitoring and communication protocols that may be put into place.
- **Time extension applications for power plants** – the draft Rule 007 now requires applicants to: (i) explain why the construction or alteration completion date will not be met, why the time extension is required and provide an updated project schedule; (ii) submit a new noise assessment (Rule 012: Noise Control); and (iii) provide a list of contact information for all persons contacted for the Participant Involvement Program ("**PIP**").
- **Solar glint and glare assessment** – solar power plants must complete a solar glare impact assessment when receptors are located within 800 metres from the boundary of the project.
- **Shadow flicker** – wind power plants must complete a shadow flicker impact assessment that predicts the shadow flicker at any dwellings within 1.5 kilometres from the centre point of the tower of the closest wind turbine.
- **Battery storage** – the draft Rule 007 includes 9 new information requirements for battery storage projects. If the battery storage project is intended to operate as a transmission facility, a needs identification document application by the AESO is required.

– **Maximum impact scenario** – the draft Rule 007 acknowledges that technology continues to advance rapidly, often in less time than it takes for a project to progress through the development, permitting and pre-construction cycle. To provide applicants with flexibility to accommodate technology selection after a project is approved, the Commission allows applicants for wind, solar, thermal or "other" power plants to submit applications wherein the site-layout and/or equipment may change after the approval is obtained. For such applications, an applicant must submit a final project update to the Commission at least 90 days prior to the start of construction, provided that applicants may not change the project site boundary for wind and solar power plants.

The Commission held the final stakeholder consultation session for feedback on the draft Rule 007 on November 12, 2020. It is anticipated that the revised final Rule 007 will be released in early 2021.

Rule 007: AUC PIP/Consultation

As part of the application process for a new power plant, substation, transmission line or industrial system, the AUC requires applicants to submit an application pursuant to AUC Rule 007. As part of the application process, proponents are required to develop and implement a PIP prior to submission of an application to the AUC. PIPs include: (i) distribution of a project-specific program; (ii) responding to questions and concerns from stakeholders; and (iii) discussion options, alternatives, and mitigation measures.

In meeting the PIP requirements under AUC Rule 007, applicants are to ensure that all parties, including First Nations and Métis, whose rights may be directly and adversely affected by a proposed development, are informed of the application and have had an opportunity to voice their concerns.

As currently drafted, AUC Rules 007 and 020 do not specify how Indigenous consultation should occur in the context of a PIP. In December 2019, the AUC released a bulletin for the *Interim Direction on Indigenous Consultation* for proponents while the AUC reviews its application requirements for consultation with Indigenous communities. The AUC first sought engagement and advice on its Indigenous consultation framework in July 2020. The AUC's goal was to have clear requirements for Indigenous consultation by the fall of 2020. In November 2020, the AUC sought feedback from stakeholders on a revised draft of AUC Rule 007. As of the date of this publication, no publication had been finalized.

Market Surveillance Administrator

2020 Market Share Offer Control

Section 5 of the Fair, Efficient and Open Competition Regulation requires that the MSA publish the percentage of offer control held by electricity market participants at least annually. An electricity market participant's total offer control is measured as the ratio of megawatts under its control to the sum of maximum capability of generating units in Alberta.

For the Period January 5th, 2020
Hour Ending 17

Company	Control (MW)	%
TransAlta	3,268	20.6%
Balancing Pool	2,284	14.4%
Heartland Generation	1,796	11.3%
ENMAX	1,446	9.1%
Capital Power	1,321	8.3%
Suncor	1,182	7.5%
Other	4,245	26.8%
Total Dispatchable	15,542	98.1%
Total Non-Dispatchable	309	1.9%
Grand Total	**15,851**	**100.0%**

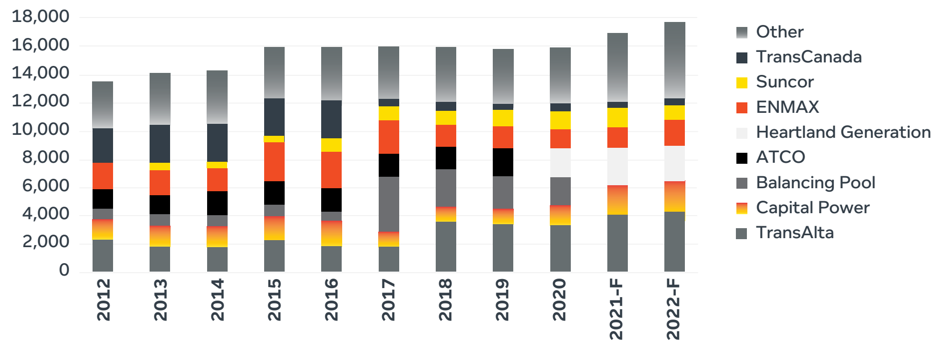
Source: Market Surveillance Administrator, 2020 Market Share Offer Control Report (February 28, 2020) p. 3

Alberta's total capacity increased 281 MW since the last market share offer control assessment on January 31, 2019. The increase in total capacity was primarily due to the addition of several wind assets.

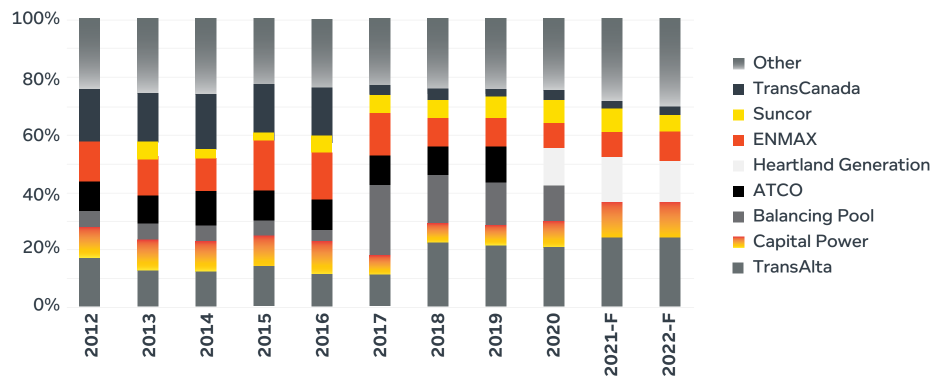
Expiry of Historical Government-Backed Power Purchase Arrangements

As the historical government-backed PPAs held by the Balancing Pool were set to expire on December 31, 2020, the MSA calculated the estimated market share offer control for 2021 and 2022. In its calculation, the MSA assumed that the offer control of the PPA units will be transferred from the Balancing Pool to TransAlta Corporation, Capital Power Corporation and Heartland Generation Ltd. at the end of 2020 and the units will remain in operation.

Control Of Generation
(MW)



Control Of Generation
(Percentage)



Source: Market Surveillance Administrator, 2020 Market Share Offer Control Report (February 28, 2020) p. 5

The MSA estimates that the market share of electricity market participants with greater than 5% market share offer control will decrease in 2021 to 69% and will decrease in 2022 to 67%. This is largely due to the increase in renewable generation assets being built under the Renewable Electricity Program, which offsets the increase in offer control for TransAlta Corporation, Capital Power Corporation, and Heartland Generation Ltd. due to the expiry of the PPAs.

Revised MSA Compliance Process

Since the last MSA Compliance Process revisions in October 2016, new Alberta Reliability Standards and sections of the ISO Rules have been adopted (including CIP reliability standards). The MSA has indicated that there may be opportunities to clarify its Compliance Process in order to reduce regulatory burdens for market participants and help achieve Alberta's red tape reduction targets.

On December 4, 2020, the MSA released the final revised MSA Compliance Process and associated forms which came into effect on the same date. The changes include clarifications of communication protocols, self-reporting requirements, the enforcement process and outcomes (including forbearance), compliance forms, and opportunities to provide information.

ALBERTA INDIGENOUS OPPORTUNITIES COOPERATION

On November 26, 2019, the *Alberta Indigenous Opportunities Act* received royal assent and established the Alberta Indigenous Opportunities Corporation ("**AIOC**"). The AIOC's mandate is to facilitate investment by Indigenous groups in natural resource projects and related infrastructure in the Province. The AIOC is able to provide up to $1 billion in loan guarantees which supports Indigenous groups to raise capital and invest in natural resource projects.

On September 9, 2020, the AIOC announced that its first commitment would be a loan guarantee to a consortium of six Alberta First Nations to participate in the Cascade Power Project. Cascade is a 900 MW combined cycle natural gas fired power plant being constructed near Edson, Alberta and is currently expected to be completed in 2023.

RED TAPE REDUCTION & REGULATION PROCESS

To encourage investment in the Province, the Alberta government is reducing regulatory burdens. Their efforts are reflected by the passing of Bill 22 which introduced the *Red Tape Reduction Implementation Act* (the "**Bill 22**"). Bill 22 is omnibus legislation amending 14 pieces of legislation administered by six different ministers. These amendments are intended to increase efficiency, speed up regulatory approval processes and attract investment. For example, Bill 22 will remove the requirement for the Alberta Energy Regulator ("**AER**") to obtain Cabinet approval prior to issuing final approval for new Alberta oil sands projects. In its assessment of a proposed project, the AER must consider, among other things, whether the project is in the public interest. In doing so, the AER follows a pre-determined process and generally uses evidence-based measures to minimize environmental, stakeholder and Indigenous impacts. The requirement for Cabinet approval frequently subjected projects to significant public and political debate causing delay, which in turn politicized the project and increased the regulatory uncertainty. By removing the requirement for Cabinet authorization for soil sands projects, Alberta is attempting to increase transparency and centralizing decision-making authority with the AER, as an expert tribunal. However, pursuant to the AER's governing legislation, it does not have jurisdiction to consider or assess the adequacy of Aboriginal consultation. As a result, the uncertainty arising from Cabinet approval may simply be replaced by additional scrutiny to ensure the duty to consult has been discharged and the honour of the Crown upheld.

AUC Report

In support of the Alberta government's goal of reducing regulatory burden, in addition to the rule changes discussed above, the AUC made the same commitment to improve the efficiency of its processes and procedures. The AUC Procedures and Process Review Committee (the "**Committee**"), an expert committee, was established to look into and prepare a report on the processes and procedures of rate proceedings to make them more productive and efficient. The Committee made 30 recommendations to improve AUC adjudicative efficiency, the most fundamental one being that the Commission implement a comprehensive assertive case management approach to its procedures and processes.

The AUC accepted 29 of the 30 report recommendations. These recommendations are to be adopted immediately. The AUC concluded that a legislated tightening of the AUC's decision-making timeframes was unnecessary.

The Committee concluded that efficiency and productivity of the AUC's processes and procedures would be improved if the AUC were to adopt an "assertive case management approach that is more reflective of the Commission's own needs and responsibilities, while respecting the principles of procedural fairness." The recommendations set out by the Committee and being implemented by the Commission pertain to the following procedures and processes:

- Assertive Case Management
- Confidentiality
- Cross-Examination
- Scoping of Issues
- Hearings
- Argument
- Scheduling
- Interrogatories
- Decisions

What's Next?

Against the backdrop of Alberta's Recovery Plan and the federal government's Healthy Environment and a Healthy Economy Plan (the "**Federal Climate Plan**"), there are a number of opportunities in Alberta for power generation and new energy development and diversification. The Federal Climate Plan is the cornerstone of the federal government's commitment in the 2020 Speech from the Throne to create over one million jobs, and includes 64 new measures and $15 billion in investments. This is in addition to the Canada Infrastructure Bank's ("**CIB**") $6 billion for clean infrastructure announced in October 2020 as part of the CIB's Growth Plan, intended to target investments in clean power ($2.5 billion), the digital economy ($2 billion), energy efficiency ($2 billion), agricultural irrigation projects ($1.5 billion), and zero-emissions transportation ($1.5 billion).

> **These initiatives coupled with the retirement of Alberta's coal-fired electricity generation fleet and its merchant market, make Alberta a prime jurisdiction for investment and growth in natural gas, renewables, advanced biofuels and other new energy sources and technologies including geothermal, hydrogen and lithium.**

DIVERSIFICATION OF ALBERTA

Hydrogen

On October 6, 2020, Alberta released the Natural Gas Vision and Strategy which lays out a plan for Alberta to become a global supplier of clean, responsibly sourced natural gas and related products, including hydrogen and petrochemicals. The strategy is a key part of the government's plan to recover from a period of unprecedented economic adversity.

The report identified hydrogen as a key growth area for Alberta. Alberta's strategy includes large-scale hydrogen production with carbon capture, utilization and storage ("**CCUS**") and deployment in various commercial applications across the provincial economy by 2030. The intention is to have exports of hydrogen and hydrogen-derived products to jurisdictions across Canada, North America, and globally in place by 2040.

Alberta has several advantages in the production of "blue" hydrogen, which is made with ultra-low emissions by upgrading natural gas. The carbon by-product generated from this process can then be captured and permanently sequestered underground or used for another purpose.

> **The hydrogen economy remains in its infancy, however Alberta is well positioned to be a major contributor given Alberta has the technology and pre-existing infrastructure to produce blue hydrogen.**

Further commentary on the future of hydrogen in Canada can be found on page 78 of this publication.

Lithium

Global demand for lithium is trending upwards as electric vehicles are becoming increasingly common. As they continue to get cheaper, battery capabilities improve, and concerns about climate change increase, demand for electric vehicles and their lithium components is expected to accelerate. On a global scale, it is expected that by 2025, electric vehicles will account for 10% of passenger vehicle sales, rising to 28% in 2030 and 58% by 2040.

This growth presents a major opportunity for Alberta. Alberta's oil fields hold large deposits of lithium in subsurface brine. While this subsurface lithium-brine has long been overlooked as industrial waste from oil field operations, technologies known as direct lithium extraction ("**DLE**") are being developed to access Alberta's lithium-brine potential. Considering the recent developments of DLE technologies and that Alberta's lithium originates from many of the same reservoirs as Alberta's existing oil and gas resources, Alberta is well-positioned to become a major lithium producer.

On September 23, 2020, the Province announced the establishment of the Mineral Advisory Council to provide strategic advice, guidance, and recommendations on a Minerals Strategy and Action Plan for Alberta.

Alberta's current regulatory regime does not contemplate the production and development of lithium. One function of the Mineral Advisory Council is to explore regulatory options and the regulatory changes required to implement a lithium strategy as part of Alberta's metallic and industrial minerals sector through stakeholder engagement. Some of the necessary changes required to facilitate development and production of Alberta's lithium include the following:

- Changes to the tenure permitting regulatory scheme pursuant to the *Metallic and Industrial Minerals Tenure Regulation* to better accommodate lithium. Specifically, extending the first two-year assessment period under the current 14-year term to give lithium producers more time to scale up their exploration. In addition, changes to permit inclusion of expenses related to the development of mineral extraction technologies as qualified expenditures to meet minimum spending requirements are required to facilitate extension of the regime to lithium.

- Amendments to the *Metallic and Industrial Minerals Royalty Regulation* to create royalty rate specific to lithium.

- Alberta Energy Regulator directives, legislation, and regulations that could apply or be adapted for lithium production. Clearly defined provisions in the *Responsible Energy Development Act*, the energy resource enactments, and the applicable specified enactments addressing Alberta's emerging lithium industry will be important in order for Alberta's lithium industry's growth.

Geothermal

The global geothermal power market has been projected to grow at a compound annual growth rate of 2.6% between 2019 to 2026 and reach a value of $6.8 billion. A growing interest in geothermal development can be attributed to factors such as advances in technology, improvements in the data available, the ability for geothermal to complement other industrial and commercial practices, and the potential for geothermal to serve as a relatively clean source of heat and electricity.

In Alberta, research has illustrated a potential to develop geothermal on a commercial scale with excess of 6,100 MW of thermal power capacity potential and 1,150 MW of technically recoverable electrical power capacity potential for a 30 year production period. The factors which contribute to Alberta's ability to benefit from the potential of geothermal development include natural geological advantages, the expertise of the established oil and gas sector and the opportunity to repurpose inactive oil and gas wells, well sites and existing infrastructure.

On December 9, 2020, Bill 36: *Geothermal Resource Development Act* ("**Bill 36**") received royal assent. Bill 36 is dedicated to the establishment of a regulatory framework for the development of geothermal resources in Alberta. In particular, Bill 36 establishes a framework to regulate geothermal development below the base of groundwater protection, which is the depth groundwater transitions from non-saline to saline. Bill 36 will apply retroactively to any geothermal resource development in Alberta.

Bill 36 will provide the government and industry with clarity on rules and processes, establish an approach to land use and liability management, protect landowners and mineral rights owners, and establish the government's authority to receive revenues (i.e. royalties and fees). As Bill 36 awaits proclamation, the Government of Alberta intends to engage with key industry partners and stakeholders in its efforts to implement clear and necessary geothermal regulations that will contribute to further geothermal development in Alberta.

Small Modular Reactors (SMR)

On August 10, 2020, Alberta joined New Brunswick, Ontario, and Saskatchewan in signing a Memorandum of Understanding ("**MOU**") supporting the development of small modular reactors ("**SMRs**"). This commits Alberta to work to promote the expanded use of nuclear power, a commitment that the other three provinces had made when they first signed the MOU in December of 2019.

SMRs are expected to be considerably smaller and more versatile than traditional nuclear reactors. They are smaller in both output and physical size. SMRs typically generate between 200 to 300 MW of electricity and are modular, or small enough to be readily built in a factory and shipped easily. SMR technology has particular potential for Alberta's energy sector, as it could help power oil sands facilities and further reduce the emissions intensity of Alberta oil.

On December 18, 2020, the Province endorsed the newly released Canada's SMR Action Plan. Further commentary on small modular reactors in Canada can be found on page 65 of this publication.

What To Expect In 2021

It is anticipated that 2021 will be a growth year for Albertan energy. With the release of the Alberta Recovery Plan, the phasing out of coal, increased energy storage projects, focus on innovation and push towards clean technology, it is anticipated that Alberta's electricity industry will undergo a transition in 2021.

The electricity industry can also expect to see significant regulatory change that will have sweeping effects for project developers and lenders as the AUC implements the red tape reduction initiative. It is anticipated that several outstanding issues will be resolved in 2021 providing increasing certainty for project developers and lenders. The AUC is set to release several reports and rule updates as well as hearings on significant issues. These include the release of the AUC's updated PIP guidelines and the final DSI report, which is expected to set out a regulatory framework intending to facilitate efficient outcomes in Alberta's utilities market. In addition, following the outcome of AUC Proceeding 26090 and the AUC's DSI, industry will get some clarity on the use of DCG credits and charges going forward through the distribution facility owner tariff proceedings.

Ontario Regional Overview

Authors: Reena Goyal, Karen Luu, Zachary Masoud, Seán O'Neill, George Vegh

Introduction

The power sector has faced a challenging year. As a result of the COVID-19 pandemic, the sector has faced financial stresses, a drop in demand, and disruptions to the power supply chain on an international level. In Ontario, the experience has been no different and the uncertainties from the ongoing pandemic have proven to be a challenge to forecast future electricity demand in Ontario.

We are glad to report, however, that not all was doom and gloom. Over the last year, the Ontario power sector achieved important milestones by way of its first successful capacity auction and Ontario Energy Board ("**OEB**") governance reform; and while we are saying goodbye to a generation procurement program from a different era, stakeholders of the power industry can look forward to more opportunities in the future to contribute to the development of OEB initiatives, Independent Electricity System Operator ("**IESO**") capacity auctions and a new framework for the Long Term Energy Plan.

COVID-19: A Most Uncertain and Cautionary Year

The emergence and unprecedented nature of the COVID-19 pandemic has put significant pressure on Ontario's power sector. Among other challenges, it needs to determine how to best achieve effective planning for a reliable electricity system given: (i) the pandemic's impact on electricity demand following the implementation of Ontario's COVID-19 isolation measures; and (ii) the forecasting uncertainties associated with the unknown duration of the COVID-19 crisis and its related economic impacts.

The impact of the lockdown on energy demand cannot be overstated. As we wrote following an update from the IESO on April 23, 2020 , top-line numbers showed a significant demand reduction across all hours, with both peak demand and overall consumption being down. Numbers are down for small commercial consumption, likely due to the mandatory closure of non-essential businesses, and industrial/commercial customers and wholesale customers. These declines were to be expected given Ontario's response to COVID-19 and the resulting sharp drop in energy consumption.

Counterintuitively, this sharp drop in demand was expected to cause energy prices to rise because the system's fixed costs were allocated over a smaller base of consumption. As a result, the government of Ontario took steps to assist Ontarians staying home by freezing the price of electricity throughout 2020 under the *Emergency Management and Civil Protection Act*. Most recently, the government held the January price of electricity at 8.5 ¢/kWh, which price was equal to the off-peak price set by the OEB for January 1, 2021. In addition, the government capped the Global Adjustment charge for Class A and Class B energy customers. As we wrote on May 15, 2020 when these measures were first announced, the government prevented rising energy prices by capping the prices paid by consumers and paying the gap between what the energy costs and what consumers are being charged. It may take many years for consumption to return to pre-pandemic levels and the economy may continue to struggle throughout early 2021. This may result in further deferrals of energy costs and the implementation of new measures to help energy consumers.

This uncertainty is highlighted in the IESO's 2020 Annual Planning Outlook in which the IESO provided for two different scenarios of economic recovery. Unsurprisingly, both scenarios are predicated on lower demand than forecasted in the IESO's 2019 Annual Planning Outlook. The first scenario assumes a shallow economic recession in 2020 and early 2021 followed by a rapid economic recovery in 2021 and 2022, with demand expected to reach pre-pandemic levels by the end of 2022. The second scenario assumes a deep economic recession until the end of 2021, followed by a slow multi-year economic recovery starting in 2022, with demand not expected to reach pre-pandemic levels until 2024. What is most noteworthy is that long-term demand in both scenarios will ultimately exceed the IESO's 2019 forecast. The IESO highlights the resiliency and stability of the industrial sector, an increase in residential usage reflecting work-from-home arrangements, rapid growth in indoor agriculture, robust near-term growth in the mining subsector and new rail transit electrification projects as some of the reasons for such longer-term demand.

Becoming Best in Class: Modernizing the OEB

In December 2017, the previous Ontario government launched a review of the OEB to consider the appropriate mandate, role and structure of a modern energy regulator. Over a year later in October 2018, the OEB Modernization Review Panel (the "**Panel**") provided its final report (the "**Report**").

On May 9, 2019, the Ontario government passed Bill 87, *Fixing the Hydro Mess Act, 2019*, which amends various statutes, including the *Ontario Energy Board Act, 1998*, as part of its comprehensive reform of, among other things, the structure of the OEB. In accordance with the recommendations of the Report, the changes included the creation and appointment of a board of directors with a non-executive Chair as well as a Chief Commissioner who would be responsible for adjudication. The Chief Executive Officer was also granted specific powers to make rules and issue codes.

On October 1, 2020, this new OEB governance structure became official. Accordingly, the OEB welcomed a new leadership that included Richard Dicerni as Chair, Susanna Zagar as Chief Executive Officer, and Lynne Anderson as Chief Commissioner.

That same day, the Ministry of Energy, Northern Development and Mines (the "**Ministry**") also delivered its mandate letters setting out the government's expectations and performance priorities with respect to the OEB. In a letter to the Chair, Minister Greg Rickford set out his vision for a modernized OEB – one which was informed by the work of the Panel, and which includes two broad categories of actions. Some notable examples of actions are excerpted below:

1 Independence and Accountability – Strengthening Trust in the OEB through Implementing Governance Reform

- Ensure that governance and operational roles and responsibilities are clearly defined
- Reinforce effective operational and communication protocols within the organization that support the independence of adjudication

2 Certainty, Efficiency, and Effectiveness – Promoting Operational Effectiveness, Finding Cost Efficiencies, and Reducing Regulatory Burden

- Reform processes for rule and code-setting to include a greater role for stakeholders, including consideration of a cost/benefit approach
- Reduce regulatory burden on licensees, namely the number of reporting requirements and corporate governance requirements for local distribution companies and natural gas utilities
- Build on efforts to move towards online-only filing of OEB applications
- Report publicly through the OEB's Annual Report on how the OEB has simplified and streamlined practices and procedures

The Ministry also emphasized the importance of providing updates to the government and other stakeholders about the OEB's progress, particularly with respect to changes brought forward by the Chief Commissioner to improve the efficiency and effectiveness of the adjudication process. To that end, Ministry staff will be tasked with providing quarterly updates on the OEB's progress. The OEB will be similarly expected to employ tools and develop mechanisms to consistently track and measure such progress.

Building upon these mandate letters, the Chief Executive Officer provided an update on October 30, 2020. In her letter, Ms. Zagar stated that three initiatives were underway to demonstrate the OEB's near-term priorities as part of a broader and more comprehensive plan to achieve a level of governance and operations befitting a "top-quartile regulator". The OEB will:

conduct a financial review of its operations to ensure that it is delivering "value for money for the people of Ontario";

terminate its Corporate Governance Guidance for OEB Rate-Regulated Utilities initiative and the associated reporting and record keeping requirements it originally proposed; and

promote stakeholder engagement, starting with a survey of stakeholders to inform the development of new key performance indicators.

For now, observers should be relieved to see the government and the OEB adopting the recommendations of the Report. The first steps in modernizing the Province's energy regulator are underway and it is exciting to see some clear and deliberate actions by the OEB's new

leadership to increase transparency and stakeholder engagement. However, observers would be wise to remember that there remain other challenges – some of which are highlighted in the Report and others that are not.

As we noted last year, there are other processes and policy instruments apart from adjudication decision-making for which additional transparency is required. Although the mandate letter is helpful with its reference to cost-benefit analysis, it would be useful if the record for policy decisions was made explicit. In addition, there must be increased regulatory oversight of procurement of capacity in the electricity sector. The current reforms will be of limited benefit to Ontario ratepayers if these challenges are not addressed.

As discussed below, one forum in which these issues can be addressed is the government's proposed initiative to address increasing "the effectiveness, transparency and accountability of energy decision-making in Ontario." The government will be holding consultations in this regard in 2021 and we are hopeful that this will involve the first enduring fact-based and transparent independent oversight for planning, procurement and market rule amendments.

Going Once, Going Twice... Sold! (on the IESO's Capacity Auction)

On December 10, 2020, the IESO announced the results of a province-wide capacity auction, which secured 992.1 megawatts (MW) of capacity from 26 successful market participants. A combination of eligible resource types, including electricity loads, generators, and energy storage participated in the auction.

This much-anticipated round of capacity procurement comes after the IESO delayed the auction (originally scheduled for June 2020) following reduced electricity demand resulting from COVID-19. It is also the IESO's first capacity auction following the replacement of the IESO's former Demand Response Auction program.

WHAT ARE THE RESULTS?

The clearing price for the 992.1 MW procured was $197.58/MW-day, representing a significant decrease of approximately 26% from the Demand Response Auction in 2019. Participants have committed to provide capacity for summer 2021, which is intended to assist in managing peak seasonal loads. Capacity commitments ranged from 245.6 MW down to 1.1 MW. Although the IESO did not disclose the total number or identity of unsuccessful bidders, it revealed that more than 1,700 MW worth of resources enrolled in the auction.

WHAT STANDS OUT?

> **This was the first time the IESO invited electricity generating resources to compete together with load-side resources. Notably, HQ Energy Marketing Inc. received a capacity commitment for 80 MW as a system-backed import.**

While this represents a significant development, the majority of successful bidders in this round remained electricity loads. This result may alleviate the trepidation felt by load-side participants, some of whom felt that expanding the capacity auction to electricity generators

would limit their ability to compete. As described on our blog, this was the subject of an application brought earlier in 2020 by the Association of Major Power Consumers in Ontario before the OEB, which was ultimately denied.

Also of note is the successful participation of one non-aggregated energy storage entity, which is particularly interesting given the increased market focus on this rapidly developing technology and the continuing desire for regulatory certainty for storage. As described on our blog, whether additional administrative mechanisms are required to enable energy storage to efficiently compete will turn in part on the pace of storage technology development in Ontario and the physical and financial characteristics of competing capacity market participants. Although much work remains to facilitate the full deployment of energy storage in Ontario, the results of the first capacity auction may be a reassuring signal for storage advocates.

THE NEXT STAGE

Capacity auctions are an important mechanism for ensuring short-term resource adequacy and are integral to the IESO's three-part resource adequacy framework (the "**Framework**"). Under the Framework, the IESO has committed to use capacity auctions for procuring short term capacity in 2021 and 2022. It is anticipated that auctions will be used for medium-term resource adequacy in conjunction with RFPs and contract-based arrangements. To that end, the IESO plans on seeking feedback, improving the capacity auction process and operationalizing the Framework in early 2021.

All plans, however, are subject to COVID-19. As stated above, forecasting future energy demand could be challenging for years to come. Therefore, capacity auctions may become a more attractive mechanism for dealing with short-term fluctuations in demand. This may be true particularly given that, as described below, the government has revoked the last of the IESO's active electricity generation procurement programs – the hydroelectric contract initiative. With the termination of this program, hydroelectric facilities that are no longer under contract would be eligible to participate in the IESO's capacity auctions going forward.

For these reasons, the ongoing evolution of the IESO's capacity market should remain the subject of much attention from stakeholders in the power industry, and the procedural success of the first capacity auction should be seen as a positive signal for both load-side resources (which remained the majority of success bidders) and for new entrants (such as generation-side resources and energy storage resources).

A Final Farewell to Generation Procurement

In 2009, the then Minister of Energy issued a directive which established the Hydroelectric Contract Initiative ("**HCI**") program, which permitted existing hydro facilities without electricity contracts to obtain 20-year contracts, among other things, as part of the Province's electricity generation procurement program.

Over a decade later, the last of the government's electricity generation procurement programs comes to an end. On February 14, 2020, the government issued a directive under section 25.32 of the *Electricity Act, 1998* (the "**Electricity Act**") to terminate the HCI program. Starting on March 1, 2020, the IESO ceased accepting applications and negotiations underway with respect to the program, and all steps necessary to discontinue and wind down the HCI program were initiated. Notably, the directive will not affect the rights and obligations of parties to existing contracts under the HCI program.

The Ever-Evolving Long-Term Energy Plan

In 2016, the Electricity Act was amended to include requirements for developing a provincial long-term energy plan ("**LTEP**"). Ontario Regulation 355/17 (the "**Regulation**") of the *Electricity Act*, which establishes a 3-year timeframe for issuing the LTEP, required the next LTEP to be issued by February 2021.

On July 27, 2020, the Ontario government issued a proposal to revoke the Regulation and remove the 3-year timing requirement and such removal became effective on January 1, 2021.

According to a letter issued by the Ministry on January 5, 2021, revoking the Regulation is the first step toward the government's plan to reform Ontario's long-term energy planning process. Through the design and implementation of an improved framework – which is the reason why an LTEP will not be released in February 2021 – the Ministry intends on clarifying the role of the government, the IESO and the OEB in energy planning. The Ministry also intends to solicit broad-based feedback on the Environmental Registry of Ontario from across the Province through a formal 90-day engagement.

Apart from possibly shifting greater responsibility for the LTEP to the IESO and the OEB, however, the intended changes remain ambiguous. Stakeholder concerns raised in the proposal's comment period included negative impacts to transparency and accountability, and delays to the planning process, timely responses to climate change impacts, and/or energy transition processes. In response, the Ministry merely pointed to addressing these concerns through the upcoming consultation and design process.

Nevertheless, this engagement is a welcomed departure from the current government's historically closed-door approach to energy planning. With this engagement, stakeholders have an opportunity to participate in the potential reform of resource planning going forward by influencing the role of the government and its agencies, including potential legislative changes to implement same.

Québec Regional Overview

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Following a transition period (without any new large private energy procurement in the Province since 2013), certain public statements of Québec government officials in 2020 have shed some glimmers of hope that Québec's market may open up again to private energy procurement in the coming years. The last few years have been a period of transition in which the Québec government put a hold on new procurement and focussed on exporting its significant electricity surplus, while using the surplus to support the energy transition, including the electrification of transportation. Now that the electricity surplus has shrunk, Hydro-Québec, the Province's government owned public electricity utility, now forecasts that additional long-term electricity supplies will be needed as early as 2025. Hilo, Hydro-Québec's new energy saving subsidiary, will also be a part of the Province's supply mix.

In summer 2020, Québec premier François Legault stated that the price of wind power had become more attractive and that the next power projects in Québec would likely be wind power. Around the same time, Hydro-Québec consulted the power generation industry on electricity supply with a view to identifying how to best meet future energy needs. Discussions included potential changes to the regulatory framework governing electricity supply. The Province's exportation strategy also generates renewed optimism with respect to a potential expansion of wind energy supply in Québec.

In spring 2020, Hydro-Québec announced that it would temporarily suspend the international investment activities it had been pursuing since 2016 through its arm, Hydro-Québec International, in order to focus on provincial opportunities and to play a key role in the Province's economic recovery amid the COVID-19 pandemic. Hydro-Québec's investment (via a private placement of common shares) in Innergex Renewable Energy and the related co-investment strategic partnership announced in February 2020 could be an indication of how Hydro-Québec intends on pursuing international opportunities in the near future.

Québec's Electricity Export Strategy

It is a stated objective of Hydro-Québec to increase its exports beyond its borders. By the same token, the utility hopes to support the decarbonisation of northeastern North America.

The COVID-19 pandemic has had an impact on Hydro-Québec's exports to markets outside of Québec. Lower energy demand brought on by the pandemic resulted in lower market prices in export markets, particularly in the first quarter of 2020. Warmer seasonal temperatures

also caused a decrease in demand for electricity. The decreased demand led to a corresponding decrease in average export prices, which dropped to 4.4 ¢/kWh (from 4.9 ¢/kWh in 2019) in the first six months of 2020, and dropped to 4.3 ¢/kWh (from 4.4 ¢/kWh in 2019) in the third quarter of 2020. Net electricity export amounts were also down in 2020 compared to 2019 by 1.7 TWh for the first half of 2020 and by 3.2 TWh for the third quarter of 2020.

Although projected electricity demand continues to be subject to change as the uncertainty generated by the pandemic continues, Hydro-Québec's Strategic Plan for 2020-2024 does set out certain export-related initiatives that are expected to continue despite the pandemic.

In terms of infrastructure, the construction of the 1,550 megawatt Romaine hydroelectric project continues and is expected to be completed in 2021. The Province also continues to update and expand its transmission infrastructure in Québec in order to support its exportation plans.

Hydro-Québec continues to promote the load balancing capacity of its hydroelectric assets in addition to its hallmark as a clean and renewable energy source. Despite recent movement towards small modular nuclear reactor technology in Canada (as discussed in our article on page 65 of this publication), Québec remains optimistic about the appeal of its hydropower to other provinces.

The Province has renewed its efforts to increase hydroelectricity exports to the state of New York, in respect of which both Governor Andrew Cuomo and New York City have reiterated their interest. Hydro-Québec continues to evaluate a potential interconnection project that would connect the Hertel station in La Prairie, Québec, to the Champlain Hudson Power Express, a proposed 1,000 megawatt high voltage direct current submarine power cable located under Lake Champlain and the Hudson River. In May 2020, the Champlain Hudson Power Express project, led by developer Transmission Developers Inc., received approval from the US Federal Energy Regulatory Commission and the Canada-US Internal Boundary Commission. Construction activities are now expected to begin in 2021 with commercial operation commencing in 2025.

In October 2020, Hydro-Québec announced its intention to submit a formal bid to supply New York City with clean energy. The New York State Energy Research and Development Authority and the New York Power Authority are soliciting proposals for 1,500 megawatts of power and, if a Hydro-Québec proposal is accepted, the development of an interconnection link between Québec and New York City would move forward. This announcement was spurred by a regulatory change to New York's Clean Energy Standard, which added a category entitled "Tier 4" pursuant to which existing hydropower is now eligible for renewable energy credits when delivered directly into New York City. As a result of this change, electricity distributors using hydropower will now be able to obtain credits from the state of New York, making it in turn more attractive to enter into business with producers such as Hydro-Québec.

Hydro-Québec also continues to advance the New England Clean Energy Connect ("**NECEC**") 142-mile transmission line project, a joint effort with Central Maine Power aimed at eventually delivering up to 1,200 megawatts of electricity to the New England region. In November 2020, the United States Army Corps of Engineers issued a federal environmental permit for the NECEC project which paves the way for Central Maine Power to begin construction of the transmission line. Two other important permits were also issued by the Land Use and Planning Commission (January 2020) and the Department of Environmental Protection (May 2020) in favour of the NECEC project. Most recently, on January 15, 2021, the project received presidential approval from the US Department of Energy. While the project is still awaiting approvals in the US from ISO New England, as well as certain other municipal approvals, all major required permits have now been obtained in the US from state and federal agencies. In Québec, the interconnection portion of the project has received approvals from the *Régie de l'énergie du Québec* and the *Commission de protection du territoire agricole du Québec*. If construction proceeds according to schedule, the NECEC project will be commissioned in 2022.

Québec's 2030 Plan for a Green Economy

On November 16, 2020, the Québec government announced the 2030 Plan for a Green Economy along with its first implementation plan, backed by a budget of $6.7 billion dollars, for the 2021-2026 period. The government's primary objective under the plan is to tackle climate change and to reduce greenhouse gas emissions by 37.5% below the 1990 levels by 2030.

With the transportation sector currently accounting for 43% of Québec's greenhouse gas emissions, the government undertakes to make the electrification of the transportation industry a priority in its 2030 Plan for a Green Economy. The industrial sector will also benefit from various initiatives, such as financial support for greenhouse gas emissions reduction projects and research and development, to reduce its carbon footprint.

Québec also intends to diversify its energy portfolio in the upcoming years with new renewable energy sources, such as renewable natural gas, green hydrogen and bioenergy.

Targets include a 50% increase in bioenergy production and 10% renewable natural gas in Québec's natural gas network by 2030.

This aligns with the recent announcements of Hydro-Québec's construction of an electrolyzer facility and Québec's investment in Enerkem's biofuel project in Varennes. Under the first implementation plan of the 2030 Plan for a Green Economy, $213 million will be allocated to initiatives with respect to production and distribution of renewable natural gas and respectively $30 million and $15 million to support the innovation in the bioenergy and green hydrogen sectors through the Technoclimat program.

In recognition of hydrogen and bioenergy's important contributions to achieving the greenhouse gas emissions reduction target, the Québec government will be unveiling, in fall 2021, a green hydrogen and bioenergy strategy to further enhance local production and consumption and to identify favourable conditions for the development of the green sector.

Public Investments in Green Hydrogen and Bioenergy

In 2020, significant investments in green hydrogen and bioenergy projects were announced by the Québec government, including in respect of Enerkem's Varennes project and Bioenergy La Tuque's residual forest biomass project.

In December 2020, the government announced an investment, through Investissement Québec, of $160 million in the Varennes project developed by Enerkem and its partners Shell, Suncor and Proman, to set up a plant to produce biofuels from non-recyclable residual materials. The government's support of this project is expected to also allow the installation by Hydro-Québec of what would be the world's most powerful electrolyser for producing green hydrogen (88 megawatts).

In November 2020, the Québec government announced the award of an approximately $5.9 million grant to Bioenergy La Tuque to demonstrate the pre-commercial potential of producing biofuels from residual forest biomass, a project developed by Bioenergy La Tuque, the Attikamek nation and the Finnish company Neste, a world leader in biofuels.

The development of such renewable energy projects is in line with the objectives of Québec's 2030 Plan for a Green Economy and the government's desire to position the Province of Québec as a leader in the production of green hydrogen and bioenergy, which are complementary to electrification to reduce greenhouse gas emissions.

Hilo – Hydro-Québec's Smart Energy Offering to Customers

In late 2019, Hydro-Québec announced that it was launching Hilo, a new subsidiary offering personalized products and services to enable customers to use energy in a more efficient manner. By launching Hilo, Hydro-Québec aims to reduce electricity use in Québec, especially during winter peak periods, in order to increase exports to other North American markets, and to simplify energy management in Québec through the use of new smart technologies.

In 2020, Hilo began to offer products and services intended for consumer home use. Such products ranged from smart thermostats to smoke detectors and light bulbs, which can be managed through a single app in order to control real-time energy consumption. Hilo's customers can be eligible for certain cash rewards by participating in "Hilo challenges". "Hilo challenges" will take place in winter peak consumption periods, during which customers are invited to reduce the set point temperature of their thermostats. During a typical winter, Hilo expects that there will be approximately 30 "Hilo challenges".

Hilo does not currently offer products and services to businesses, but expects to offer, in the future, solar energy self-production solutions combined with smart energy storage, as well as electric vehicle fleet management solutions. The goal will be to help businesses optimize their electricity consumption and reduce their electricity bills by developing strategies using available smart technologies.

Environmental Law

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Key Developments in 2020

In 2020, 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's New Environmental Assessment Regime Now in Force: In March 2018, the BC government launched the process for revitalizing the Province's environmental assessment ("**EA**") process. On December 18, 2019, the Province's new *Environmental Assessment Act*, 2018 ("**BC EAA**") came into force. The BC EAA introduces 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. BC's Environmental Assessment Office ("**EAO**") has entered into the The Impact Assessment Cooperation Agreement ("**IACA**") with the Impact Assessment Agency of Canada ("**IAA**"). The IACA is a consolidation and update of existing memoranda of understanding between the EAO and the IAA that have been in place in various forms since 2004 (under the previous **Environmental Assessment Act, 2002**). Under the IACA, cooperation options include coordination, substitution, and joint review panel. The IACA applies to all projects being assessed under the new BC EAA.

Delay to Carbon Tax Increase: In response to the COVID-19 pandemic, the BC government announced in March 2020 that the scheduled increase to the Province's carbon tax rate would be delayed until April 1, 2021. BC's carbon tax rate is currently $40 per tonne of carbon dioxide equivalent ("**tCO_2e**"), which is expected to increase to $45 per tCO_2e in April 2021.

Refreshed Mandate for Minister of Environment: In a snap fall election, the provincial NDP won a majority government on October 24, 2020. The BC Minister of Environment, the Honourable George Heyman, retained his position and was given a refreshed mandate after the election. The Minister's priorities focus on the Province's post-pandemic economic recovery, the phase-out of plastics, setting sectoral and interim targets to reach BC's 2030 greenhouse gas ("**GHG**") emissions target, legislating a target of net-zero carbon emissions by 2050, ensuring that additional funding is available to support industry efforts to reduce GHG emissions, implementing a provincial Climate Preparedness and Adaptation Strategy, accelerating the move toward a net-zero emission bus fleet powered by zero-emissions technologies, advancing public transportation projects, and creating a Watershed Security Strategy. To assist the Minister in meeting the Ministry's commitments, a Parliamentary Secretary for Environment has been assigned to support delivery of the identified priorities.

BC Sets 2025 Emissions Reduction Target: In December 2020, the BC Government set a new near-term emissions reduction target for 2025, supported by a new 2020 Climate Change Accountability Report detailing actions under the CleanBC climate change plan. The new target requires a reduction in GHG emissions to 16% below 2007 levels by 2025. It provides a benchmark on the road to BC's legislated emission targets for 2030, 2040 and 2050 of 40%, 60% and 80% below 2007 levels, respectively.

GHG Emissions - Reduction Targets

ALBERTA

Conservation and Reclamation Directive for Renewable Energy Operations: Alberta Environment and Parks ("**AEP**") provides an environmental stewardship framework and regulates natural resource access, allocation, and use through planning, policy and compliance assurance programs through the *Environmental Protection and Enhancement Act* ("**EPEA**") and the *Conservation and Reclamation* Regulation ("**C&R Regulation**"). Under EPEA, after a specified land activity (which includes the land that is being or has been used or held for or in connection with the construction, operation or reclamation of a renewable energy operation) has been decommissioned, operators must obtain a reclamation certificate. Reclamation certificates are managed through AEP and the Alberta Energy Regulator.

The conservation and reclamation planning requirements outlined in AEP's *Conservation and Reclamation Directive for Renewable Energy* Operations (14 September 2018) create minimum regulatory requirements and set out the information that must be submitted to the AUC with an application for an AUC power plant approval. Operators must maintain a conservation and remediation plan ("**C&R Plan**"), the content of which will vary based on whether the operator is currently seeking approval for a new project or whether the operator has received approval from the AUC.

On or after January 1, 2020, all AUC power plant applications for renewable energy projects must meet the requirements under the *Conservation and Reclamation Directive for Renewable Energy Operations* (14 September 2018). AEP provides support to the AUC for the review and assessment of such C&R Plans submitted in approval applications. This is done concurrently and in alignment with wildlife reviews and, when approved, the formal disposition application on public lands. Renewable energy projects that submitted an approval application to the AUC prior to January 1, 2020, unless otherwise directed, are considered to have met the initial conservation and reclamation requirements under the **Conservation and Reclamation Directive for Renewable Energy Operations** through the environmental evaluation or environmental plan submitted to the AUC.

A Coal Policy for Alberta repealed: In an effort to modernize Alberta's coal development policies and facilitate favourable conditions for investment in coal export, the Government of Alberta repealed *A Coal Policy for Alberta* (also known as the 1976 Coal Policy) in May 2020. Following the rescission of the 1976 Coal Policy, restrictions on issuing coal leases within the former coal categories 2 and 3 were removed. Coal leasing, exploration and development within category 1 remained restricted. As described in Alberta Energy's May 25, 2020 Coal Information Bulletin 2020-02, proponents with active coal lease applications were offered a right of first refusal by Alberta Energy for the coal leases they held. Following the right of first refusal, Alberta Energy intended to open all lands for public lease sales, except within category 1 lands.

Alberta Energy completed one sale on December 15, 2020, but later, on January 18, 2021, cancelled leases issued in category 2 lands within that offering period. As of January 20, 2021, all plans for additional lease sales within category 2 lands were suspended. Although the leases issued in this first public offering period were cancelled, a number of new leases on category 2 land have been issued since the revocation of the policy in June of 2020.

The rescission of the 1976 Coal Policy was intended to update the leasing process in Alberta, however, it resulted in a lack of clarity around intended protections on sensitive lands within the Province. In early February 2021, the Government of Alberta reinstated the 1976 Coal Policy, effective February 8, 2021, following a significant amount of public concern and outcry. The objections to the revocation of the 1976 Coal Policy include an application for judicial review (*Blades, et al v Her Majesty the Queen in Right of Alberta and the Minister of Energy for the Province of Alberta*, Alberta Court of Queen's Bench Court File No. 2001-08938) and many objections from local organizations, governments and Indigenous groups, some of which adopted resolutions questioning the decision to revoke the policy, or demanded the Government of Alberta reinstate the policy. With the reinstatement of the 1976 Coal Policy, the Government of Alberta intends to engage in public consultation, seeking input from all Albertans to implement a modernized policy.

The 1976 Coal Policy restricts the development of coal in certain areas within the Province, and has done so since 1976. The scope of the policy is wide-ranging and includes, among other items, a land use classification system. The policy divides the Province into four categories which dictate where and how coal leasing, exploration and development could occur. The original intention of the 1976 Coal Policy was to ensure there was appropriate regulatory and environmental protection measures in place before new coal projects were authorized. This objective is now being met by Alberta's current regulatory, land use planning and leasing systems (i.e. the *Alberta Land Stewardship Act*, the *Responsible Energy Development Act*, the *Coal Conservation Act*, the *Water Act* and the *Environmental Protection and Enhancement Act*).

The 1976 Coal Policy prevents development of coal resources in category 1 lands on the eastern slopes of the Rockies and only permits the development of new underground mines (rather than open-pit mines) in category 2 lands. Following the reinstatement of the 1976 Coal Policy, the Government of Alberta provided specific direction to the Alberta Energy Regulator ("**AER**"), including: (i) a prohibition on mountain-top removal and the application of all restrictions under the 1976 coal categories, including all restrictions on surface mining in category 2 lands; and (ii) until such time as the Government of Alberta can engage in widespread consultation on a new coal policy, all future coal exploration approval in category 2 lands remain paused.

Although direction has been given not to process new applications for approval and exploration programs, this prohibition does not apply to exploration programs already approved by the AER. Nor does the reinstatement of the policy revoke the leases granted to proponents in the time between the initial revocation of the policy and the time of its reinstatement.

Going forward, all coal development projects will continue to be considered through the existing AER review process. This review is based on each project's merits, including its economic, social and environmental impacts.

Liabilities Management Statutes Amendment Act, 2020: In April 2020, Alberta enacted new legislation intended to strengthen the powers of the AER and the Orphan Well Association ("**OWA**"). Alberta also extended its loan to the OWA by up to $100 million to facilitate its reclamation efforts and to generate oil services jobs in March 2020. The legislation amends the *Oil and Gas Conservation Act* and the *Pipeline Act* by:

- Establishing an additional duty for licensees and approval holders to "provide reasonable care and measures to prevent impairment or damage in respect of a well, facility, well site or facility site." Impairment or damage is defined as "impairment or damage that results in or could reasonably be expected to result in harm to the integrity of a well or facility or harm to the environment, human health or safety or property". If AER concludes that a licensee or approval holder cannot fulfil this new duty, the duty must be fulfilled by the working interest participants (or "**WIPs**"). If the WIPs are not performing this new additional duty "in a manner satisfactory" to AER, then under the new Section 26.2(3) of the *Oil and Gas Conservation Act*, AER may order the licensee, WIP or a delegated authority under Part 11 (which now includes the OWA) to provide reasonable care and measures to discharge the duty.

- Adding the OWA to the definition of "delegated authority" allows the OWA to assume management and control of wells, with any production being subject to the consent of the owner or holder of the mineral rights.

- Expanding the scope of activities that the funds within the Orphan Well Fund can be used for including costs associated with monitoring the behaviour of orphan wells and facilities and the costs of a receiver.

- Expanding the OWA's jurisdiction to include undertaking remediation activities associated with orphan sites in addition to suspension, abandonment and reclamation activities and that the costs of these activities can now be recovered from the Orphan Well Fund.

Notably missing from this legislation, and promised by Alberta's government, are comprehensive measures to address the challenges facing Alberta's oil and gas industry and the increasing number of orphan well and facility problems, including underfunding for end of life liabilities. However, more comprehensive measures have been promised and are anticipated in 2021.

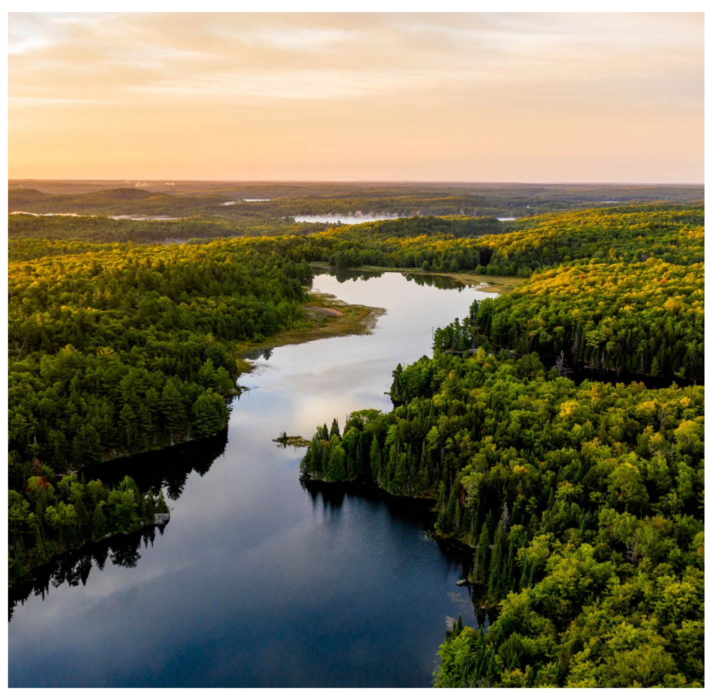
ONTARIO

Amendments to Ontario's *Environmental Assessment Act*: The *COVID-19 Economic Recovery Act, 2020* (Bill 107; Royal Assent on July 21, 2020) made significant changes to Ontario's *Environmental Assessment Act* (the "**EAA**") which will come into force in phases, the timing of which has not yet been specified.

The EAA currently applies to public sector undertakings and only to some private sector undertakings that are specifically designated by order or regulations. Public sector undertakings, unless exempted, are required to undergo either a self-directed class environmental assessment process or, for some larger undertakings with potential significant and unknown environmental effects, an individual environmental assessment that is subject to Ministerial approval. Bill 197 replaces Part II of the EAA, which deals with individual environmental assessments, with a new Part II.3 which requires projects designated by regulation to complete a comprehensive environmental assessment. Bill 197 also replaces Part II.1, which deals with class environmental assessments, with a new Part II.4 which requires projects designated by regulation to complete a streamlined environmental assessment process. Once the changes are in force, the EAA will apply to designated undertakings (similar to the manner in which the federal *Impact Assessment Act* regime applies to designated undertakings) that are required to undergo either a comprehensive environmental assessment or a streamlined environmental assessment.

Approved class environmental assessments will continue to apply to undertakings until they are revoked and replaced with designating regulations and streamlined assessment requirements. On September 11, 2020, the Ontario government posted for comment a draft "Projects List" of projects subject to comprehensive environmental assessments. The draft Projects List was similar in scope of the designated projects list under the federal *Impact Assessment Act*. It will be interesting to see if and how this list changes once public comments are considered.

Industrial Greenhouse Gas Emissions in Ontario: In September 2020, the Supreme Court of Canada ("**SCC**") heard appeals from the Alberta, Saskatchewan and Ontario Courts of Appeal on the constitutionality of the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"). This is discussed in further detail below. The Ontario Court of Appeal, in a decision released in June, 2019, held that the GGPPA was constitutional. A decision from the SCC is anticipated in the second half of 2021.



In September 2020, just prior to the SCC hearing, the federal Minister of the Environment and Climate Change announced that the federal government had determined that Ontario's emission performance standards (as set out in the *Greenhouse Gas Emissions Performance Standards* regulations under the Ontario *Environmental Protection Act*) met the requirements of the GGPPA. As a result, Ontario's industrial emitters are in the process of transitioning from the federal output-based pricing system under the GGPPA to the Ontario emissions performances standard program. Both the federal and provincial programs are based on setting emission performance standards for industries. The generation of electricity using fossil fuels is an industrial activity that is regulated, subject to certain threshold requirements, under both the federal output-based pricing system and the Ontario emission performance standards system.

Notwithstanding the foregoing, the SCC's decision on the constitutionality of the GGPPA remains relevant to Ontario, because the GGPPA also imposes a charge on fossil fuel distribution in Ontario, which continues to apply pending the Court's decision.

Greener Fuel: Ontario amended its clean fuel regulations to gradually increase the requirement for renewable fuel (such as ethanol) content in gasoline and diesel. The provincial government revoked previous regulations which addressed renewable fuel content in gasoline and diesel and created a new regulation: Ontario Regulation 663/20 *Cleaner Transportation Fuels: Renewable Content Requirements for Gasoline and Diesel Fuels*. For gasoline, fuel suppliers will be required to have an average renewable content in regular gasoline of 11% by 2025, 13% by 2028 and 15% by 2030.

Court Quashes the Minister's Revocation of the Renewable Energy Approval for the Nation Rise Wind Farm Project. As we reported last year, in December 2019, the Ontario Minister of the Environment, Conservation and Parks granted an appeal of the Renewable Energy Approval ("**REA**") issued for the operation of the Nation Rise Wind Farm. In granting this appeal, the Minister revoked the REA, citing reasons related to irreversible harm to bats in the local area. On May 13, 2020, the Ontario Divisional Court quashed the Minister's decision to revoke the REA on the basis that it was unreasonable because: (i) the Minister had acted without statutory authority in raising new issues on the appeal; (ii) the Minister applied the wrong legal test in making his decision; and (iii) the Minister had made factual conclusions that were not supported by the evidentiary record. The Minister did not appeal the Court's decision and the Nation Rise wind project is proceeding. Further commentary on this decision can be found in our litigation review on page 56 of this publication.

QUÉBEC

Québec Sets 2030 GHG Emissions Reduction Target: On November 1, 2020, Bill 44 (*An Act mainly to ensure effective governance of the fight against Climate Change and to promote electrification*) ("**Bill 44**") came into force. Bill 44 confirms Québec's target of reducing the Province's GHG emissions by at least 37.5% in 2030 compared to 1990 levels, and modified the provincial governance structure regarding energy transition measures and the Province's Green fund. On November 16, 2020 the Québec Government also announced its 2030 Plan for a Green Economy backed by a $6.7 billion budget for the 2021-2026 period. Among other things, the Plan seeks to

chart Québec's course towards carbon neutrality by 2050, and also provides for the following targets:

- **1.5 million electric vehicles on the road in Québec by 2030;**
- **No sales of new gasoline-powered vehicles as of 2035;**
- **100% of governmental cars, SUVs, vans and minivans and 25% of pickup trucks running on electricity by 2030;**
- **15% ethanol in gasoline by and 10% in biobased diesel fuel by 2030;**
- **50% reduction in emissions related to heating for buildings by 2030;**
- **60% reduction in emissions from government buildings by 2030;**
- **10% renewable natural gas (RNG) in the network in 2030;**
- **50% increase in bioenergy production by 2030; and**
- **70% of off-grid systems energy supply from renewable sources by 2025.**

New Regulations to Modernize the Environmental Authorization Regime: Further to the adoption of a new environmental authorization regime on March 27, 2017 (Bill 102), Québec adopted a new set of environmental regulations which came into force on December 31, 2020, including the *Regulation respecting the regulatory scheme applying to activities on the basis of their environmental impact*). Among other things, these regulations are intended to accelerate the environmental permitting process by streamlining the documents and information required in support of permit applications for projects deemed to represent a moderate environmental risk. The regulations also broaden the list of activities that may qualify for a declaration of compliance, a fast-track permitting process for activities deemed to represent a low environmental risk.

FEDERAL

New Impact Assessment Regime Now in Force: 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 was designed to replace the current *Canadian Environmental Assessment Act, 2012*. Bill C-69 received Royal Assent in June 2019 and came into force in August 2019.

Carbon Pricing Update: In October 2016, the federal government announced that it would establish a minimum price on carbon starting at $10 per tonne of carbon dioxide equivalent ("**CO_2e**") in 2018, increasing by $10 per year until it reaches $50 per tonne of CO_2e by 2022. This approach was recently reviewed (as discussed below) to confirm the path forward, including continued increases in stringency. The federal carbon pricing backstop is governed by the *Greenhouse Gas Pollution Pricing Act* and consists of two components: (i) a charge on 21 types of fuel and combustible waste that are consumed within a backstop jurisdiction and which is administered by the Canada Revenue Agency; and (ii) an output-based pricing system that applies to emission-intensive industrial facilities (i.e. facilities with emissions ≥ 50,000 tonnes of carbon dioxide equivalent, or CO_2e), starting in January 2019 and is administered by Environment Canada and Climate Change. The fuel charge began to apply in: (i) Saskatchewan, Manitoba, Ontario and New Brunswick on April 1, 2019; (ii) Nunavut and Yukon on July 1, 2019; and (iii) Alberta on January 1, 2020.

Federal Government Releases Climate Plan – *A Healthy Environment and a Health Economy*: On December 11, 2020, the federal government released its *Healthy Environment and a Healthy Economy Plan* (the "**Federal Climate Plan**"), which builds on the *Pan-Canadian Framework on Clean Growth and Climate Change* and provides a road map forward to meet the country's 2030 emissions reduction target under the Paris Agreement of 30% below 2005 levels by 2030. Together with the Pan-Canadian Framework, the federal government expects to achieve reductions within the range of 32 to 40% below 2005 levels by 2030, thereby exceeding Canada's emissions reduction target under the Paris Agreement. The Federal Climate Plan is also intended to establish the building blocks to reach Canada's goal of net-zero emissions by 2050, which was announced by the federal government in 2019. The Federal Climate Plan outlines actions in five main areas, including: (i) energy efficiency in homes and buildings; (ii) lower emission transportation options; (iii) increasing the price on carbon pollution; (iv) supporting the decarbonization of Canadian industry; and (v) building more resilient communities. The Federal Climate Plan also excludes solid and gaseous fuels from the scope of the Clean Fuel Standard, which will now cover only liquid fossil fuels.

Constitutional Challenge to the Federal *Greenhouse Gas Pollution Pricing Act*: The GGPPA came into force on June 21, 2018 and sets out the regulatory framework for the federal carbon pricing backstop system, which consists of two components: (i) a fuel levy, and (ii) an output-based pricing system ("**OBPS**") for large industrial emitters. The purpose of the GGPPA is to ensure there is a minimum national standard on GHG emissions to spur emission reductions across the economy. Part 1 of the GGPPA imposes a levy on GHG-producing fuels and combustible waste, while Part 2 implements the OBPS.

Four provinces challenged the constitutionality of the GGPPA: Alberta, Ontario, Saskatchewan and Manitoba. Each of the decisions from the Ontario Court of Appeal ("**ONCA**"), Saskatchewan Court of Appeal ("**SKCA**") and the Alberta Court of Appeal ("**ABCA**") challenging the constitutionality of the GGPPA (collectively, the "**Appeals**") were heard together by the SCC in September 2020 and a decision is anticipated in the second half of 2021. Manitoba's judicial review application was heard by the Federal Court of Canada on December 7, 2020.

Each of the decisions from the Ontario and Saskatchewan Courts of Appeal upheld the GGPPA as constitutional on the basis that the GGPPA is constitutionally valid under the federal government's "national concern" branch of the "peace, order and good government" ("**POGG**") powers. A finding that the GGPPA is properly enacted under the national concern powers means that the subject matter which the GGPPA legislates requires the need for one national law. The ABCA was the only court to find the GGPPA as unconstitutional and held that the GGPPA's regulation of GHG emissions exceeded the ambit of any federal head of power.

The SCC is considering whether the federal government has the authority to legislate on the subject matter of the GGPPA.

At a high-level, whether the SCC finds that the GGPPA is constitutional is contingent on whether it can find that the GGPPA, and its subject matter, properly fall under a federal head of power, such as the national concern branch of the POGG powers contained in Section 91 of the *Constitution Act*, 1982.

Federal Government Introduces Draft Regulations for Clean Fuel Standard: On December 18, 2020, Environment & Climate Change Canada published the proposed *Clean Fuel Regulations* ("**CFR**") in Part I of the Canada Gazette. Efforts to develop a Clean Fuel Standard started in 2016, and the objective of the CFS is to achieve 30 million tonnes of annual reductions in GHG emissions by 2030. The proposed CFR would require liquid fossil fuel primary suppliers (i.e. producers and importers) to reduce the carbon intensity ("**CI**") of the liquid fossil fuels they produce in, and import into, Canada from 2016 CI levels by 2.4 gCO_2e/MJ in 2022, increasing to 12 gCO_2e/MJ in 2030. The proposed CFR would also establish a credit market whereby the annual CI reduction requirement could be met via three main categories of credit-creating actions: (1) actions that reduce the CI of the fossil fuel throughout its lifecycle, (2) supplying low-carbon fuels, and (3) specified end-use fuel switching in transportation. Parties that are not fossil fuel primary suppliers (e.g. low-carbon fuel producers and importers) would be able to participate in the credit market as voluntary credit creators by completing certain actions. In addition, the proposed CFR would retain the minimum volumetric requirements (at least 5% low CI fuel content in gasoline and 2% low CI fuel content in diesel fuel and light fuel oil) currently set out in the federal *Renewable Fuels Regulations* ("**RFR**") and the RFR would be repealed. The draft regulations are available for a 75 day comment period, ending in March 2021. Final regulations will be published in late 2021, with the coming into force of the regulatory requirement in December 2022.

Establishment of the Emissions Reduction Fund (ERF): On October 29, 2020, the Minister of Natural Resources launched the $750-million Emissions Reduction Fund to reduce methane and GHG emissions. The Fund will provide repayable funding to eligible onshore and offshore oil and gas companies to support investments that reduce GHG emissions by adopting greener technologies and to help maintain jobs during the current environment of economic hardship and uncertainty. The program will offer up to $650 million to the onshore upstream and midstream oil and gas sector to lower or eliminate routine venting of methane rich natural gas from conventional, tight and shale oil and gas operations, through either repayable contributions (for reduction of methane) and partially repayable contributions (for methane elimination). Up to $75 million will also be invested in offshore emission reductions by investment in the following programs:

Offshore Deployment Program –
A $42 million investment supporting capital projects designed to either reduce offshore GHG or improve the environmental performance of offshore oil spill monitoring, detection and response activities; and

Offshore RR&D Program –
A $33 million investment supporting research, development and demonstration projects that advance solutions to decarbonize Newfoundland and Labrador's offshore industry. This program is being delivered in collaboration with Petroleum Research Newfoundland and Labrador.

Consultations on new Canada Water Agency: In December 2020, the Minister of Environment and Climate Change and the Minister of Agriculture and Agri-Food jointly announced the launch of public consultation to help establish the new Canada Water Agency to help manage Canada's fresh water resources. Consultation will occur until May 31, 2021 and comments can be posted on ECCC's online PlaceSpeak Platform. The issues being considered at outlined in the Canada Water Agency Discussion Paper, "Toward the Creation of a Canada Water Agency".

The Year Ahead

BRITISH COLUMBIA

BC EAA Regulations Still Under Development: While most of the regulations supporting the BC EAA came into force in December 2019, there are several regulations still under development as part of the Province's EA revitalization process. The following regulations are in development and being engaged on with Indigenous nations, stakeholders, the public and industry: *Dispute Resolution Regulation; Capacity Funding Regulation*; and *Regional/Strategic Environmental Assessment Regulation*.

Carbon Tax Increase: In response to the COVID-19 pandemic, the BC government announced in March 2020 that the scheduled increase to the Province's carbon tax rate would be delayed until April 1, 2021, when the carbon tax rate will increase to $45 per tCO_2e. In April 2022, there will be another scheduled increase to $50 per tCO_2e to keep it in line with the federal carbon pricing benchmark.

BC to Set Sectoral Emission Reduction Targets: As noted above, the BC Government set a new near-term emissions reduction target for 2025, which provides a benchmark on the road to BC's legislated emission targets for 2030, 2040 and 2050 of 40%, 60% and 80% below 2007 levels, respectively. The BC Government is expected to establish sectoral targets before March 31, 2021, and to develop legislation to formalize BC's commitment to achieving net-zero emissions by 2050.

Working Towards BC's Environmental Priorities: In 2021, we expect the BC Government to develop and implement initiatives on the range of its Ministerial priorities including climate preparedness and adaptation, reducing plastic pollution, reducing GHG emissions, and improving public transportation.

ALBERTA

Key Developments to Watch: As Alberta continues to diversify its economy, new and existing legislation and environmental regulation will play a role in providing incentives for development and investments. Significant opportunities exist in emerging technology, renewable energy development and in Alberta's traditional oil and gas industries. Key developments to watch include the outcome of the SCC decision with respect to the constitutionality of the federal GGPPA, future changes to the liability regime for oil and gas assets, and the roll-out of Alberta's stimulus investments.

> **Changes to the liability regime for oil and gas assets has the potential to impact other growing industries such as geothermal and lithium development, as changes and regulations are enacted to enable the reuse and repurposing of infrastructure and wells for new purposes.**

ONTARIO

Amendments to Ontario's *Environmental Assessment Act*: As noted above, most of the significant changes that have been made to Ontario's *Environmental Assessment Act* (the "**EAA**") have not yet come into force. It is likely that the Ontario government will finalize the comprehensive projects list in 2021, i.e. the list of projects that will be subject to comprehensive environmental assessments under the EAA, and that regulations to transition individual environmental assessments to the designated comprehensive environmental assessment regime will be released. We would also expect that the government will start to roll out regulations that replace class environmental assessments and set out the projects that will be subject to the new, streamlined environmental assessment process.

Industrial Greenhouse Gas Emissions in Ontario: The SCC's decision on the constitutionality of the GGPPA is expected in 2021 as noted in the federal section of this publication. The decision will be relevant for Ontario, as the GGPPA imposes a charge on fossil fuel distribution in Ontario which is currently in effect. If the Court rules that the GGPPA is constitutional, the fuel levy will continue to apply. If the Court finds that the GGPPA is not constitutional, the fuel levy will not apply and regulation of GHG emissions in Ontario will (for the time being) be limited to the emission performance standards that apply to industrial emitters, as set out in the *Greenhouse Gas Emissions Performance Standards* regulations under the Ontario *Environmental Protection Act*.

QUÉBEC

Omnibus Bill amending the *Environment Quality Act* (EQA) and its Regulations: The Government of Québec is expected to table an omnibus bill in 2021 to continue the ongoing modernization of the EQA, with a view to simplifying administrative processes and adapting the permitting and administrative requirements based on the environmental risks associated with each project.

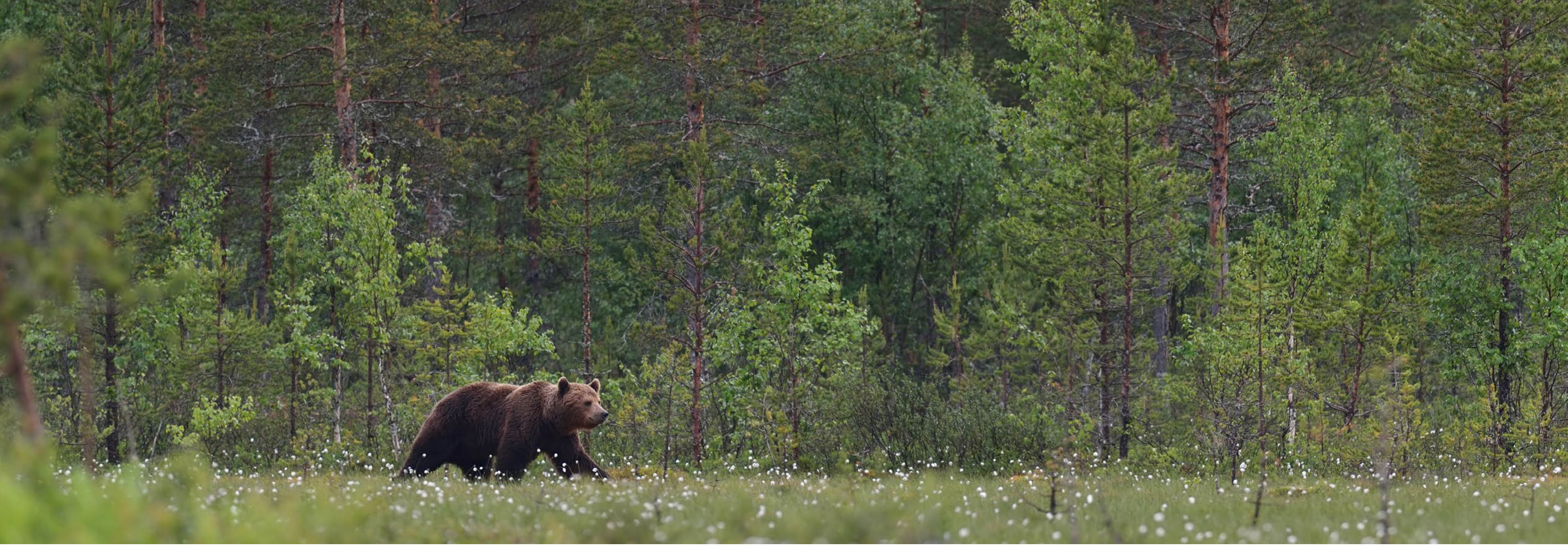
New Rules for the Cap-and-Trade System for 2024-2030: In 2021, the Government of Québec is expected to publish the proposed rules for the allocation of carbon emission credits for the 2024-2030 period under the Province's cap-and-trade system for GHG emissions. These new rules are highly anticipated by large industrial operators and are likely to include new measures aimed at encouraging further reductions in the carbon footprint of Québec's main GHG emitters.

FEDERAL

Canada's Net-Zero by 2050 Legislation: In November 2020, the federal government introduced Bill C-12, *An Act respecting transparency and accountability in Canada's efforts to achieve net-zero greenhouse gas emissions by the year 2050*). The proposed legislation is expected to pass in 2021. With the introduction of Bill C-12, Canada joins over 120 countries in committing to net-zero emissions by 2050, including the UK, Germany, France, and Japan. The Healthy Environment and a Healthy Economy Plan is intended to establish the building blocks to reach Canada's goal of net-zero emissions by 2050.

Actions Under Federal Climate Plan: In addition to the priorities outlined in the Federal Climate Plan, the federal government has committed to developing Canada's first-ever national adaptation strategy. The Federal Climate Plan also contains new measures to support Indigenous climate leadership. One of the more notable policy proposals under the Federal Climate Plan includes continued annual carbon price increases of $15 per tonne (beginning in 2022) until the carbon price reaches $170 per tonne in 2030 (under the Pan-Canadian Framework, the carbon price will reach $50 per tonne by 2022).

SCC Decision Expected on GGPPA: As noted above, a decision from the SCC on the constitutionality of the GGPPA is expected in the second half of 2021. It is challenging to predict the likely outcome of the SCC Appeals. That said, considering that there are provincial appellate courts that have decided differently and the GGPPA is a high profile and significant law, it is unlikely the SCC will do anything other than uphold the law or strike it down in its entirety. Cases concerning issues of federalism, and particularly the powers given to the federal government under the national concern branch of the POGG power, are rare, adding further uncertainty to the outcome of the Appeals.



Aboriginal Law

Authors: Bryn Gray and Selina Lee-Andersen[1]

Aboriginal law and policy relevant to energy and resource development projects continued to evolve in 2020. As discussed below, there were a number of notable duty to consult cases and both the federal and BC governments took further steps to implement the UN Declaration on the Rights of Indigenous Peoples.

Key duty to consult cases and developments

CONSULTATION IS NOT ASSESSED ACCORDING TO A STANDARD OF PERFECTION

The highest profile duty to consult case this past year was the Federal Court of Appeal's decision in *Coldwater First Nation v Canada (Attorney General)* relating to the Trans Mountain Pipeline Expansion Project ("**TMX Project**"). This was a judicial review of the federal Cabinet's decision to approve the TMX Project for the second time subject to numerous conditions. The TMX Project involves the twinning and expansion of an existing pipeline from Edmonton to Burnaby, BC. It would increase capacity from 300,000 to 890,000 barrels a day and the number of tankers from 5 to 34 per month.

The first decision was previously set aside by the Federal Court of Appeal in *Tsleil-Waututh Nation v. Canada* after the Court had found that the federal government had not met the duty to consult. The second approval was issued after the federal government had undertaken additional consultation and implemented further measures to address concerns of Indigenous groups, including amending six conditions and putting forward eight accommodation measures focused on addressing marine safety, spill prevention, response capacity, cumulative effects, fish and fish habitat, quieter vessels, and further terrestrial studies.

> **Several Indigenous groups challenged the second approval, arguing that the Crown had still not fulfilled the duty to consult. The Federal Court of Appeal concluded that the Cabinet decision was reasonable and that the flaws identified with Indigenous consultation in Tsleil-Waututh decisions had been addressed through reasonable and meaningful consultation.**

The *Coldwater* decision provides a helpful summary of key principles relating to the duty to consult. The Federal Court of Appeal re-affirmed that consultation must be meaningful in that the Crown must show that "it has considered and addressed the rights claimed by Indigenous peoples in a meaningful way" and that it is more than just "a process for exchanging and discussing

1 The authors gratefully acknowledge the assistance of Sarah Chiavarini and Nishant Jain.

information". The Court noted that the process of meaningful consultation can result in various forms of accommodation but that "the failure to accommodate in a particular way, including by way of abandoning the Project, does not necessarily mean that there has been no meaningful consultation." The Court noted that goal is to reach an overall agreement but that will not always be possible and that "reconciliation does not dictate any particular substantive outcome". The Court reiterated that Indigenous groups have reciprocal obligations to not frustrate the Crown's reasonable good faith efforts to engage in consultation, that the duty to consult does not provide a veto over projects, and that Indigenous concerns can be balanced against "competing societal interests" when adequate consultation has taken place.

The Federal Court of Appeal undertook a detailed review of the various alleged deficiencies raised by the Indigenous applicants and determined that they did not render the process unreasonable. The Court underscored that perfection is not required or realistic and that imposing too strict of a standard of perfection, reasonableness, or meaningfulness could create a de facto veto right. In some instances, they found that the Indigenous applicants had hindered Canada's consultation efforts or taken uncompromising positions that had effectively amounted to asserting a veto. The Court also noted the number of Indigenous groups that were either supporting or not opposing the project:

"Contrary to what the applicants assert, this was anything but a rubber-stamping exercise. The end result was not a ratification of the earlier approval, but an approval with amended conditions flowing directly from the renewed consultation. It is true that the applicants are of the view that their concerns have not been fully met, but to insist on that happening is to impose a standard of perfection, a standard not required by law.

Significantly, the consultation process initiated by Canada invited the participation of 129 Indigenous groups potentially impacted by the Project and, in the end, more than 120 either support it or do not oppose it. As well, benefit agreements had been signed with 43 Indigenous groups as of June 22, 2019.... The Governor in Council was entitled under section 54 to take this broad consensus into account in concluding that the Project was in the public interest. This is a factor that also speaks to the fact that the process that has taken place is consistent with the objectives of reconciliation and honour of the Crown."

The Supreme Court of Canada subsequently denied leave to appeal of this decision.

Similar themes were also seen in *Sagkeeng v. Government of Manitoba et al* decision of the Manitoba Court of Queen's Bench. This was an application for judicial review by the Sagkeeng Anicinabe ("**Sagkeeng**") of a Ministerial decision to grant Manitoba Hydro a license to construct the Manitoba-Minnesota Transmission Project. The Sagkeeng alleged that Manitoba breached its duty to consult in issuing the licence. The Court concluded that Sagkeeng's application was premature (as they had not pursued an available statutory appeal to Cabinet) and had failed to establish that the Minister's decision was unreasonable and in breach of the duty to consult.

The Sagkeeng argued that the consultation was devoid of any substance or meaning and was "nothing more than a smile". The Court found that the Minister's licensing decision was justified and reasonable and that the consultation was meaningful having regard to the government's consultation efforts and various accommodation measures introduced to address concerns. The Court emphasized that while the consultation and accommodation may have fallen short from the Sagkeeng's perspective, reasonableness assessed in the context, and not perfection, is the standard. This decision also highlights the risks of Indigenous groups not fulfilling their reciprocal obligations in consultation. The Court stressed that consultation "is a two-way street" and seemed to be influenced by the fact that the Sagkeeng was not responsive and timely. They found that the Province attempted to establish "a robust, funded, community-based consultation process with Sagkeeng" but that the Sagkeeng "did not respond in a reasonable timely manner or show material interest in pursuing the process" and that "more could, and ought to have been done on its part".

THE SCOPE OF CONSULTATION FOR ASSERTED ABORIGINAL TITLE CLAIMS

In *Ross River Dena Council v Yukon*,[2] the Yukon Court of Appeal clarified the scope of consultation obligations in the context of Aboriginal title assertions. This was an appeal of a decision of the Supreme Court of Yukon. This decision had denied the Ross River Dena Council's ("**RRDC**") request for a declaration that the Yukon government's issuance of hunting licences and seals might adversely affect their Aboriginal title claim by permitting conduct inconsistent with their claim and that there was a duty to consult with respect to potential adverse impacts on the incidents of Aboriginal title when issuing these licences.

2 2020 YKCA 10.

On appeal, the RRDC argued that the issuance of hunting licences and seals interfered with their claimed right to exclusive use and occupation of the land and that the presence of hunters on the land would be a violation of the incidents of their asserted title claim.

The Court of Appeal dismissed the appeal for two reasons. First, the licences at issue did not itself give the licence holders the right to enter land that it could not otherwise enter. Second, the RRDC did not have proven title and as such did not have a right to control the use and occupation of the land at present or a veto over government action. The Court also noted that the RRDC had not identified any potential adverse impact to their asserted claim which could affect their ability to fully realize the benefits of Aboriginal title, if and when it is finally established. The Court noted that the RRDC's objection to non-RRDC hunters entering the area was not evidence of an adverse impact on their title claim.

> **This decision is consistent with prior Court decisions that consultation is intended to prevent irreversible damage to Indigenous interests pending proof or settlement of claims and is not intended to provide Indigenous groups with what they would be entitled to if they prove or settle their claims.**[3]

RISKS OF UNADDRESSED CUMULATIVE IMPACTS

Cumulative impacts on Aboriginal and treaty rights is an issue that is being increasingly raised in consultation relating to energy and other resource development projects. The *Fort McKay First Nation v. Prosper Petroleum Ltd*[4] decision of the Alberta Court of Appeal highlights the risks relating to unaddressed cumulative impacts and a new potential way to challenge projects where there are cumulative impact concerns.

In this case, the Alberta Court of Appeal set aside an approval of the Alberta Energy Regulator ("**AER**") for Prosper Petroleum's Rigel Bitumen Recovery Project after finding that the AER failed to consider certain issues relating to the honour of the Crown in granting the approval.

This project was within 5 km of the Fort McKay's Moose Lake reserves and in an area where the Fort McKay has Treaty 8 harvesting rights. Before the AER, Fort McKay unsuccessfully argued that the AER should delay the approval until the Moose Lake Access Management Plan ("**MLAMP**") was finalized. This was a plan that the Alberta government had committed to develop to address cumulative impacts in the Moose Lake area. Fort McKay had been in discussions with Alberta for many years about protecting the Moose Lake area due to significant cumulative impact concerns. In March 2015, then Premier Jim Prentice and Chief Jim Boucher signed a letter of intent to complete the MLAMP on an expedited basis and by September 30, 2015. The plan is still not finalized and has been the subject of ongoing negotiations.

The AER concluded that the absence of a finalized plan was not a valid reason to deny approval and Cabinet was the most appropriate place to assess this issue as the AER's approval was subject to Cabinet authorization. Fort McKay argued that the AER failed to ensure Alberta's obligation to act honourably with respect to treaty and Aboriginal rights when determining whether the approval was in the public interest.

The ABCA held that while the AER is not permitted by its legislation to consider issues of consultation it can consider issues of constitutional law as part of its determination of whether an application is in the "public interest", which includes the honour of the Crown. The ABCA found that the AER took an unreasonably narrow view of what comprises the public interest and ought to have considered whether the honour of the Crown was engaged and required delay of the approval due to the ongoing MLAMP negotiations.

In concurring reasons, Justice Greckol went further stating, "The honour of the Crown may not mandate that the parties agree to any one particular settlement, but it does require that the Crown keep promises made during negotiations designed to protect treaty rights. It certainly demands more than allowing the Crown to placate

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3 See, for example, *Ka'a'Gee Tu First Nation v. Canada (Attorney General)*, [2012] F.C.J. No. 237 at para. 123; *Adams Lake Indian Band v. British Columbia*, [2013] B.C.J. No. 1026 at paras. 95-99.

4 2020 ABCA 163.

[Fort McKay] while its treaty rights careen into obliteration. That is not honourable. And it is not reconciliation."

This decision highlights the risks of unaddressed cumulative effects and the honour of the Crown as a separate and distinct basis to challenge projects where there are significant cumulative impacts concerns, particularly with respect to established rights. Notably, the duty to consult in the context of cumulative effects on Aboriginal and treaty rights is not about addressing impacts from other projects or activities (past, present, or future) but mitigating, avoiding, or offsetting any additional incremental impacts.

DENYING APPROVAL BASED ON INDIGENOUS CONCERNS DOES NOT NECESSARILY PROVIDE A VETO

In *Redmond v. British Columbia (Forests, Lands, Natural Resource Operations and Rural Development*[5], the British Columbia Supreme Court was required to consider an appeal of a decision to deny an application to develop a small, independent run-of-river hydroelectric project that would have negative impacts on Cheam First Nation's ("**Cheam**") spiritual bathing sites. The Director of Authorisations for the BC Ministry of Forests, Lands, Natural Resource Operations, and Rural Development denied the application after concluding the impacts on the Cheam's asserted Aboriginal right to cultural practices was serious and that the proposed mitigations did not adequately accommodate those impacts.

The Cheam had informed the proponent and the Director that the proposed location of the project was an area where significant cultural activities were practiced both historically and currently, including spiritual bathing practices that required unaltered flows of water and absolute privacy. The BC Supreme Court upheld the Director's decision as reasonable and rejected the proponent's arguments that this constituted an impermissible veto for the Cheam, among other arguments advanced. The Court found that the Director had engaged in a balancing of interests – considering the impact on asserted rights of many Cheam community members on the one hand with the benefits of the small hydroelectric project which would provide limited additional renewable energy to the grid (only enough energy for approximately eight homes) and could be built elsewhere. It appears both the Court and the Director were influenced by the limited benefits of the project. There was also evidence in the record that the Cheam were generally supportive of run-of-the-river projects and would be prepared to consider other locations within their territory but the applicant was not willing to pursue alternate locations given that he had invested significant efforts in this specific location.

The Court noted that apart from the Director's duty to consult, it was also within the scope of the Director's statutory (section 11 of the *Land Act*) and policy framework to consider the overall impact and the "public's interest" in achieving reconciliation with First Nations, as there is a deep and broad public interest in reconciliation with Indigenous peoples.

In balancing the interests of both parties, the Court noted it was not unreasonable to find that the project should not be allowed in its entirety given its adverse impacts on Aboriginal rights that cannot be adequately accommodated. The Court noted that it is not unreasonable that the "balance and compromise...inherent in the notion of reconciliation" will sometimes result in a decision to disallow a project and that the "constitutional project of reconciliation is a 'shared responsibility' of all Canadians involving 'complex and competing interests', and will sometimes require administrative decision makers to make difficult decisions that impact the interests of proponents..."

5 2020 BCSC 561

The petitioner also argued that his section 2(a) *Canadian Charter of Rights and Freedoms* rights were violated, in part because the decision maker prioritized "Aboriginal spirituality" over his atheism and violated his right to a religiously neutral state. The Court found that the petitioner's Charter rights were not violated or limited and that the decision did not impede his ability to act in accordance with his atheist beliefs as he could propose the project in another area. The Court also noted that such a broad definition of what constitutes an atheist practices would afford atheism a much broader scope of protection than other religious practices and thus lead to the prioritization of atheism to the detriment of other religious practices in the balance of public decision making processes.

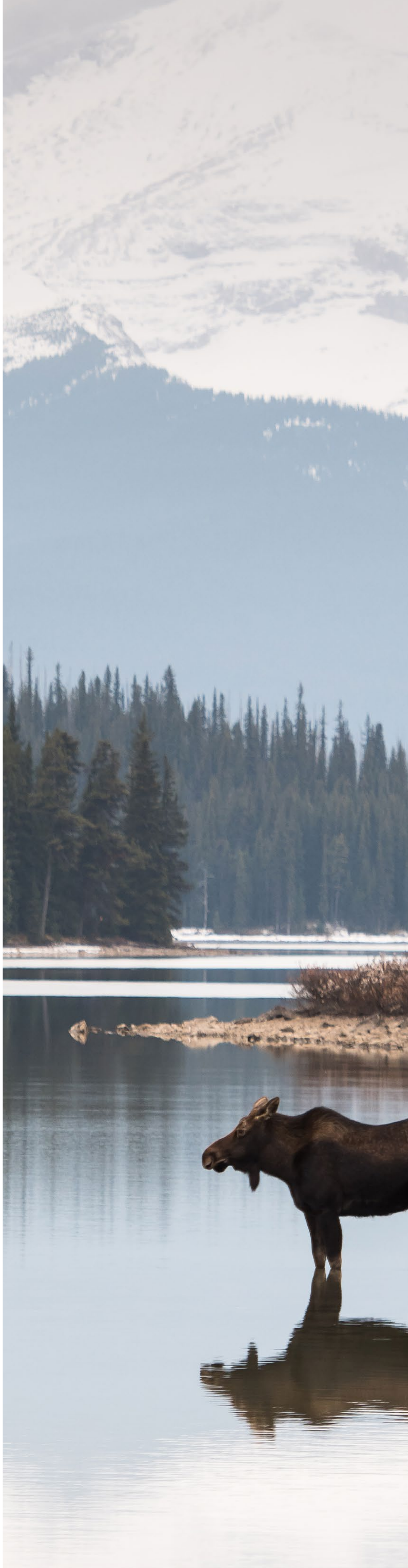
COURT REJECTS MODIFYING HAIDA TEST FOR COMPETING ABORIGINAL AND TREATY RIGHTS

In *Gamlaxyeltxw v. British Columbia (Minister of Forests, Lands & Natural Resource Operations)*,[6] the BC Court of Appeal rejected the BC Supreme Court's prior modification of the Haida test to address a conflict between asserted and established rights in consultation. In this case, the Gitanyow had an outstanding claim for section 35 Aboriginal rights in an area which overlapped with the territory subject to the Nisga'a Final Agreement. The Gitanyow challenged two decisions by the Minister of Forests, Lands & Natural Resource Operations under the Nisga'a Treaty to approve the total allowable harvest for moose and the annual management plan for Nisga'a hunters in the non-exclusive Nass Wildlife Area.

The Minister consulted with Gitanyow on the total allowable harvest but did not accept the Gitanyow's position that the moose allocation should be divided between the Nisga'a and the Gitanyow. The Minister took the position that there was no duty to consult with Gitanyow on the management plan as it would not adversely affect Gitanyow interests. The Chambers judge, affirmed by the British Columbia Court of Appeal, found that consultation was adequate regarding the total allowable harvest and the Minister did not err in concluding that there was no duty to consult the Gitanyow regarding the management plan as the management plan was expressly not applicable to non-Nisga'a hunters and therefore did not have any potential to adversely affect the Gitanyow's rights.

While the Court of Appeal largely upheld the BC Supreme Court's decision, the Court rejected the notion that the *Haida* test for the duty to consult needed to be modified in certain situations involving competing asserted and established rights. The BC Supreme Court

6 2020 BCCA 215.



had found that the *Haida* test needed to be modified to preclude a duty to consult an Indigenous group claiming s. 35 rights where the recognition of such a duty would be inconsistent with the Crown's duties to another Indigenous group with whom it has a treaty. In this case, the Gitanyow before the Minister and the BC Supreme Court sought a form of accommodation that would have required the Minister to contravene the Nisga'a Treaty. The Gitanyow modified their position on appeal and took issue with the BC Supreme Court's modification of the *Haida* test which precluded consultation altogether.

The BCCA stated that "the existence of treaty rights may limit any accommodation a rights claimant may seek, as the Crown cannot be required to breach a treaty in order to preserve a right whose scope has not yet been determined", but that it is unnecessary to modify the *Haida* test as it was sufficiently flexible to resolve conflicts between asserted and established rights. In other words, any conflict can be dealt with at the accommodation stage and such a conflict does not negate the existence of a duty to consult Indigenous groups with asserted claims that may be adversely impacted by the decision.

Policy Developments

FEDERAL GOVERNMENT INTRODUCES UNDRIP LEGISLATION

On December 3, 2020, the federal Minister of Justice introduced Bill C-15, *An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples*. This legislation was introduced to fulfill an election commitment to introduce legislation to implement UNDRIP by the end of 2020.

The legislation is generally similar to the BC *Declaration on the Rights of Indigenous Peoples Act* ("**DRIPA**", discussed in further detail below) and Bill C-262, the federal private member's bill that died on the order paper prior to the last election. The legislation is designed to provide a framework to implement UNDRIP. It requires the federal government to "take all measures necessary to ensure the laws of Canada are consistent with the Declaration", in consultation and cooperation with Indigenous peoples. It also requires the federal government to develop an action plan to achieve the objectives of UNDRIP. The action plan must be developed within three years of when the legislation comes into force and the Minister of Justice must prepare an annual public report on the implementation of the action plan. Unlike Bill C-262 and the BC DRIPA, Bill C-15 stipulates a number of requirements for the action, including that it contain provisions related to monitoring, oversight, recourse or remedy with respect to the implementation of UNDRIP.

The wording of the legislation and statements by the federal government indicate that the legislation is intended to provide a framework to implement UNDRIP but does not actually give force and effect to the UNDRIP.

This is similar to DRIPA. Notably, the federal government backgrounder indicates that the legislation does not create new obligations or regulatory requirements for industry and would not impact Canada's existing duty to consult or other consultation or participation requirements set out in other legislation such as the new *Impact Assessment Act*. These statements are consistent with the legislation being framework legislation – where any actual changes will come about at a later date through the implementation of the action plan.

The legislation does not address the issue of free, prior, and informed consent ("**FPIC**") and how the FPIC provisions of UNDRIP will be interpreted. The federal government did address this issue in its backgrounder stating that:

"Free, prior and informed consent is about working together in partnership and respect. In many ways, it reflects the ideals behind the relationship with Indigenous peoples, by striving to achieve consensus as parties work together in good faith on decisions that impact Indigenous rights and interests. Despite what some have suggested, it is not about having a veto over government decision making"

This language and prior government statements and actions suggest that the federal government is continuing to interpret Indigenous consent as an objective and not an absolute requirement in the context of resource development projects. However, the federal government is not being clear about whether there will be changes down the road that further enhance consultation requirements and scrutiny of efforts to achieve consent as part of the action plan. Notably, after indicating that the legislation would not change the duty to consult and other existing consultation requirements, the federal government stated in the C-15 backgrounder that it may "inform how the Government approaches the implementation of its legal duties going forward", without explaining how. The federal government also notes that FPIC may require "different processes or new creative ways of working together to ensure meaningful and effective participation in decision-making" but does not explain what those processes might be and how they could impact project decision-making.

These difficult questions have been deferred to another day - leaving considerable uncertainty about potential future changes to the rules of Indigenous engagement for projects and the timing any such changes.

UPDATE ON BC'S IMPLEMENTATION OF UNDRIP

BC became the first jurisdiction in Canada to adopt UNDRIP when it passed the *Declaration on the Rights of Indigenous Peoples Act* in November 2019. As a framework piece of legislation, DRIPA requires the Province to, among other things, take all measures necessary to ensure the laws of BC are consistent with UNDRIP, and prepare and implement an action plan to achieve the objectives of UNDRIP and prepare an annual report outlining its progress in implementing the action plan.

The BC government has stated that DRIPA is not intended to immediately affect or change any existing laws; rather, it is intended to be forward-looking, with a gradual and incremental implementation process as laws are introduced or amended in consultation with Indigenous peoples and stakeholders including business, industry and local government.

Like the proposed federal legislation, DRIPA does not address the issue of FPIC. The BC government's position is that it does not view FPIC as an unqualified veto right. The BC government sees the new provincial EA process as a potential model for applying FPIC in a regulatory context. BC's environmental assessment process was updated with the passage of the *Environmental Assessment Act* ("**EAA**") in November 2018. The new EAA introduced significant changes to the provincial EA process, including an early engagement process, increased opportunities for public participation, and prescriptive measures to meet the provincial government's commitment to implement UNDRIP. Under the EA process, the concept of FPIC is framed as a consensus building process, which is undertaken through cooperation between the Environmental Assessment Office and participating Indigenous nations in order to achieve consensus on process decisions of recommendations. According to the EAO User Guide, consensus is defined as "an outcome or approach that is actively supported by all participating Indigenous nations and the EAO or is not objected to by a participating Indigenous nation, while reserving their right to ultimately indicate their consent or lack of consent for a project after an assessment based upon full consideration of the project."

Although DRIPA is intended to provide the BC government with an incremental approach to implementing UNDRIP, the challenge for the provincial government (and the federal government) will be to advance its commitments through the development of an action plan and priorities in a way that does not stifle investment or create additional uncertainty. To do so, they must manage the expectations that they have created while striking a balance between competing interests.

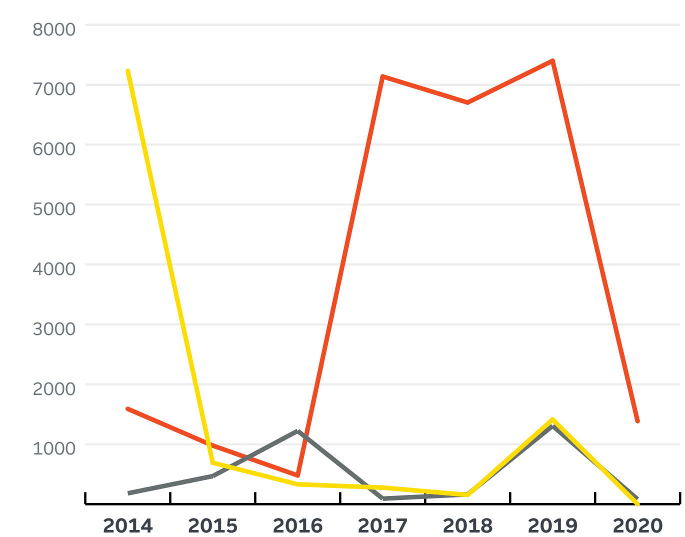
Mergers & Acquisitions

Authors: Scott Bergen, Maureen Gillis, Kerri Lui, Suzanne Murphy and Xinya Wang

The onset and continuation of the COVID-19 pandemic caused a global disruption to M&A activity in 2020. Unsurprisingly, the Canadian power sector saw a marked decline, with an aggregate domestic deal value of US$1.4 billion in 2020, compared ith US$7.4 billion in 2019.

Inbound investments in Canada by US and non-US foreign parties in 2020 similarly declined from 2019 figures. In 2020, there were no reported foreign inbound investments in the Canadian power sector from US sources and US$82 million in foreign inbound investments from non-US sources. By contrast, in 2019, aggregate deal values for US and non-US foreign investments in Canada were US$1.4 billion and US$1.3 billion, respectively.

Canada M&A Deal Value in the Electricity, Power & Utilities Sectors ($US mm)



US Inbound	7,232	691	331	276	154	1,414	0
Non-US Inbound	181	468	1,223	92	163	1,306	82
Canada Domestic	1,590	978	479	7,138	6,703	7,400	1,385

Foreign investments in the power sector by Canadian companies also fell from 2019 figures. In 2020, the aggregate deal value was US$9.4 billion, compared with US$13.4 billion in 2019. In 2020, the most significant region for outbound investment by Canadian companies was Asia, followed by the United States, Oceania/Australia, Europe and Latin America, Mexico and the Caribbean.

Domestic Investments by Canadians

Based on deal value, the major players in the 2020 Canadian power M&A market were Hydro-Québec and TransAlta Renewables Inc. ("**TransAlta Renewables**").

The largest deal by value was Hydro-Québec's acquisition of a 19.9% stake in Innergex Renewable Energy Inc. ("**Innergex**") for US$497 million. Innergex is a publicly listed Canadian energy company, headquartered in Longueuil, Québec, that develops, acquires, owns and operates renewable power generating facilities. This transaction will enable Innergex to use US$38 million to develop its 200 MW Hillcrest solar project located in Brown County, Ohio. McCarthy Tétrault acted as counsel to Innergex.

Another significant transaction in 2020 was the agreement by TransAlta Renewables to acquire a portfolio of three projects from TransAlta Corporation for US$341 million, including the remaining construction costs for the 207 MW Windrise wind project located in Willow Creek, Alberta. The three projects include the Windrise wind project, a 49% economic interest in the operating 137 MW Skookumchuck wind facility located in Thurston County and Lewis County in Washington State and a 100% economic interest in the operational 29 MW Ada cogeneration facility located in Ada, Michigan. This transaction is expected to close in separate tranches in early 2021.

Other domestic transactions included the following:

CSE Utility Management Inc., 2158815 Ontario Inc. and the management of Cricket Energy Holdings Inc. ("**Cricket**") acquired Cricket, a Canadian provider of smart home energy/metering solutions and consulting services, from Fengate Capital Management Ltd. and OZZ Electric Inc. for over US$200 million.

Canadian Utilities Limited agreed to acquire Pioneer Pipeline from Tidewater Midstream and Infrastructure Ltd. and TransAlta Corporation for US$191 million. The Pioneer Pipeline is a natural gas pipeline from the Tidewater Brazeau River facility to the Keephills and Sundance Generating Stations in Alberta.

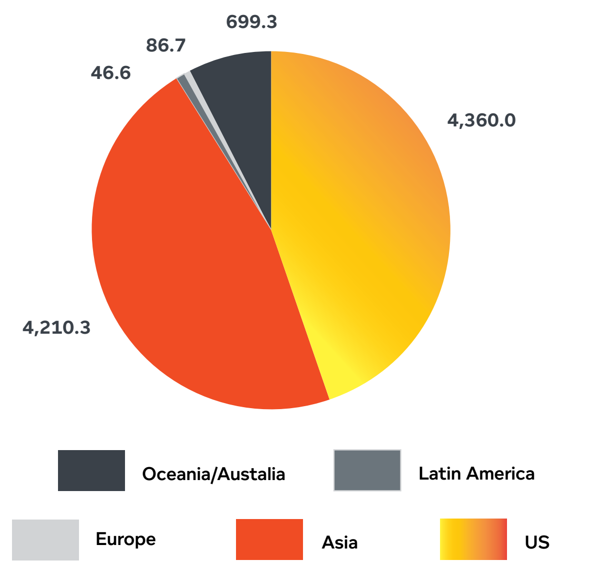
Boralex Inc. acquired a 49% stake in three wind farms in Québec from Caisse de dépôt et placement du Québec ("**CDPQ**") for US$93 million.

Heartland Generation Ltd. ("**Heartland**") acquired a 30% stake in the Muskeg River Cogeneration Station, a natural gas–fired station located in Fort McMurray, Alberta, from SaskPower International for US$29 million. Heartland's acquisition was backed by Energy Capital Partners, LLC.

Foreign Investments by Canadians

Unlike recent years, the most significant region for foreign investment by Canadian companies in the power sector in 2020 was Asia, with an aggregate deal value of US$4.4 billion. The next leading regions for power-sector investment by Canadian businesses were the United States (US$4.2 billion), Oceania/Australia (US$699 million), Europe (US$87 million) and Latin America, Mexico and the Caribbean (US$47 million). As with 2018 and 2019, there were no reported investments by Canadian companies in 2020 in Africa.

Canadian Outbound Investment in Electricity, Power & Utilities in 2020 ($US mm)



Source: MergerMarket

By deal value, the leading transactions in 2020 by Canadian companies investing in the power sector in foreign jurisdictions included the following:

CDPQ and Cathay Private Equity Ltd. Co. agreed to acquire a 50% stake in the 605 MW Greater Changhua 1 Offshore Wind Farm from Ørsted A/S for US$2.7 billion. The 605 MW Greater Changhua 1 Offshore Wind Farm is located off the coast of Changhua County, Taiwan.

Brookfield Renewable Energy Partners L.P. ("**Brookfield**") acquired the remaining 38% stake in TerraForm Power, Inc., a US-based owner and operator of clean power generation assets, not already owned by Brookfield and its affiliates for US$1.4 billion.

Ontario Teachers' Pension Plan and Abu Dhabi Investment Authority agreed to acquire an undisclosed stake in Equis Development Pte. Ltd., a Singapore-based developer, constructor, owner and operator of energy and waste infrastructure assets, for US$1.3 billion.

Brookfield agreed to acquire the solar business of Exelon Generation Company, LLC ("**Exelon Generation**"), a US-based energy company, for US$810 million, in a deal expected to close in the first half of 2021. Exelon Generation's solar business includes 360 MW of generation in operation or under construction located across 600 sites throughout the United States.

OMERS Administration Corporation acquired a 19.99% stake in TransGrid from Wren House Infrastructure Management Limited for US$699 million. TransGrid is the Australia-based owner and operator of the high voltage electricity transmission network in New South Wales and the Australian Capital Territory, Australia.

Algonquin Power & Utilities Corp. agreed to acquire a 51% stake in four onshore wind facilities in Texas from RWE AG for US$600 million. The four wind facilities are the Stella (201 MW), Cranell (220 MW), Raymond East (200 MW) and Raymond West (240 MW) wind farms.

Other 2020 Power Sector Transactions of Note

NRG Energy, Inc. agreed to acquire Direct Energy ("**Direct Energy**") from Centrica PLC ("**Centrica**") for US$3.6 billion. The sale includes substantially all of Direct Energy's North American energy supply, services and trading business, a portion of which is located in Canada. McCarthy Tétrault acted as Canadian counsel to Centrica and Direct Energy. This transaction closed on January 5, 2021.

Blackstone Group L.P. (via Blackstone Energy Partners) acquired NRStor C&I L.P. ("**NRStor C&I**"), a commercial and industrial energy storage company headquartered in Toronto, Ontario, and now known as Aypa Power from Fengate Capital Management Ltd., Lake Bridge Capital II, Inc. and certain principals. McCarthy Tétrault acted as counsel to NRStor C&I.

Potentia Renewables Inc. ("Potentia") acquired from Dream Asset Management Corporation an indirect interest in a 67 MW portfolio of operating renewable energy projects consisting of three ground-mount solar projects in Ontario (totaling 43 MW) and four operating wind farms in Nova Scotia (totaling 24 MW). Potentia develops, owns and operates renewable energy assets and is the largest rooftop solar company in Canada. The acquisition was financed by Stonebridge Financial Corporation ("**Stonebridge**"). McCarthy Tétrault acted as counsel to Stonebridge.

Elemental Energy Inc. ("**Elemental Energy**") acquired the 27 MW St. Lawrence Wind Farm, located in St. Lawrence, Newfoundland and Labrador, from EGPNA REP Wind Holdings, LLC. Elemental Energy subsequently amalgamated its two wind farm projects located in Newfoundland, St. Lawrence Wind Corp. and Fermeuse Wind Power Corp., to form Right Coast Wind Corp. McCarthy Tétrault acted as counsel to Elemental Energy.

VINCI Energies S.A. ("**VINCI Energies**") acquired Transelec Common Inc. ("**Transelec Common**"). Transelec Common is a Canadian company that constructs, manages and maintains network infrastructure, including electrical, telephone, signage cable, wind turbine and street lighting networks. McCarthy Tétrault acted as counsel to VINCI Energies.

2021 Trends

Despite a decrease in overall deal activity over the past year, a consistent theme seen across many industries, there is optimism that 2021 could present a return to a more active M&A market in the power space. We have seen an increase in acquisitions by financial sponsors, which we expect to be a continuing trend. The significant amount of dry powder available to financial sponsors, the result of both a very successful fundraising market in recent years as well as the overall decline in available opportunities for capital deployment in 2020, means there could be substantial appetite for acquisitions in 2021.

In addition, power assets and, in particular, renewable power assets, are poised to continue to see growing demand in 2021. A focus on ESG (Environmental, Social and Governance) factors, an increasingly formalized priority for investors, has thrust renewable energy and other "green" industries into a new spotlight. Specific environmental impact investors and the growing focus of diversified asset managers on ESG priorities (take for example, Brookfield Asset Management's hiring of Mark Carney as Head of ESG and Impact Fund Investing in August 2020) may result in an ever more heated market for quality renewable power assets.

Energy Litigation

Authors: Will Horne, Samuel Lepage, Kyle McMillan, Julie Parla and Sam Rogers

Alberta

NORMTEK RADIATION SERVICES LTD V. ALBERTA ENVIRONMENTAL APPEAL BOARD, 2020 ABCA 456

Whether a party has standing before a tribunal is not commonly litigated, however, the question of standing can be of critical importance to parties appearing before administrative tribunals such as the Alberta Environmental Appeal Board.

In this case, the appellant, Normtek, opposed an approval to amend a landfill approval to allow the disposal of concentrated, naturally occurring radioactive material ("**NORM**"), which had been granted by the designated director of approvals (the "**Director**"). Normtek, which is in the business of disposing of NORM, did not oppose the approval outright, but only certain conditions of the approval, which allowed for high level radioactive waste to be dumped near the surface.

After having its statement of concern rejected by the Director, who claimed Normtek was not directly affected by the approval, the company attempted to appeal the Director's decision to grant the permit to the Environmental Appeals Board (the "**Board**"). As with statements of concern submitted to the Director, the *Environmental Protection and Enhancement Act* (the "**Act**"), requires the appellant to be "directly affected" by the Director's decision. Normtek submitted that it was directly affected by the decision because the approval to allow dumping of high level waste near the surface (rather than in a deep geological formation), would affect its business and its nascent industry, which abided by national and international standards that Normtek stated were not being upheld. The Board denied standing on several grounds, including: (i) that Normtek's concerns were primarily economic; and (ii) that "[f]or the Appellant to be directly affected, they need to demonstrate on a prima facie basis either they will be impacted from radiation coming from the Landfill or that their use of a natural resource will be impacted by radiation coming from the Landfill." Normtek's application for judicial review of the Board's decision was dismissed.

The Alberta Court of Appeal considered the narrow interpretation of "directly affected" adopted by the Board to be unreasonable and unsupported by the Act. The Court noted that the economic effects of an approval may be enough to ground standing, and addressed other problems with the Board's decision, including failing to consider relevant evidence and applying an overly strict standard for the appellant to meet. Although the Court seems to advocate a lenient approach to the standing issue, it is significant that the Board in this case does not make substantive decisions, but rather reports information to the responsible Minister and makes non-binding recommendations. The gatekeeping role of the Board means that the concerns of an appellant who is denied standing will never even come to the attention of the ultimate decision maker. The Court remitted the issue of Normtek's standing back to the Board to be decided "having regard to the provisions of the Act and the evidence relevant to the determination to be made."

The implications of this case for those seeking standing before other tribunals remains to be seen, but it is certain that those seeking to challenge administrative decisions affecting their business interests will be citing it.

ECOJUSTICE CANADA SOCIETY V. ALBERTA JUDICIAL REVIEW, 2020 ABQB 364 AND 2020 ABQB 736

In 2019, the Government of Alberta launched a public inquiry under the *Public Inquiries Act* to investigate anti-Alberta energy campaigns supported by foreign organizations, and appointed a Commissioner. Ecojustice brought an application for judicial review seeking to stop the public inquiry on three grounds. That application was set to be heard in April 2020, but had to be adjourned sine die because of the emerging COVID-19 pandemic. A decision on the underlying application is expected in 2021.

Two interlocutory applications were heard in 2020 that will be of interest to those following the case. In the first, an "industry consortium" of organizations and one individual sought leave of the Court to jointly intervene in order to speak to two of the three grounds upon which Ecojustice brought its application. All were pro-industry, and the individual intervenor was outspoken about those who opposed Alberta oil and gas. Ecojustice opposed the application for intervenor status, and although the Court agreed with Ecojustice that the arguments proposed to be raised were speculative, it ultimately found that the consortium's industry perspective and direct interest in the matter weighed in favour of allowing it to intervene on one of the two matters to which it applied. Unsurprisingly, the Court cautioned the intervenors against inflammatory political rhetoric.

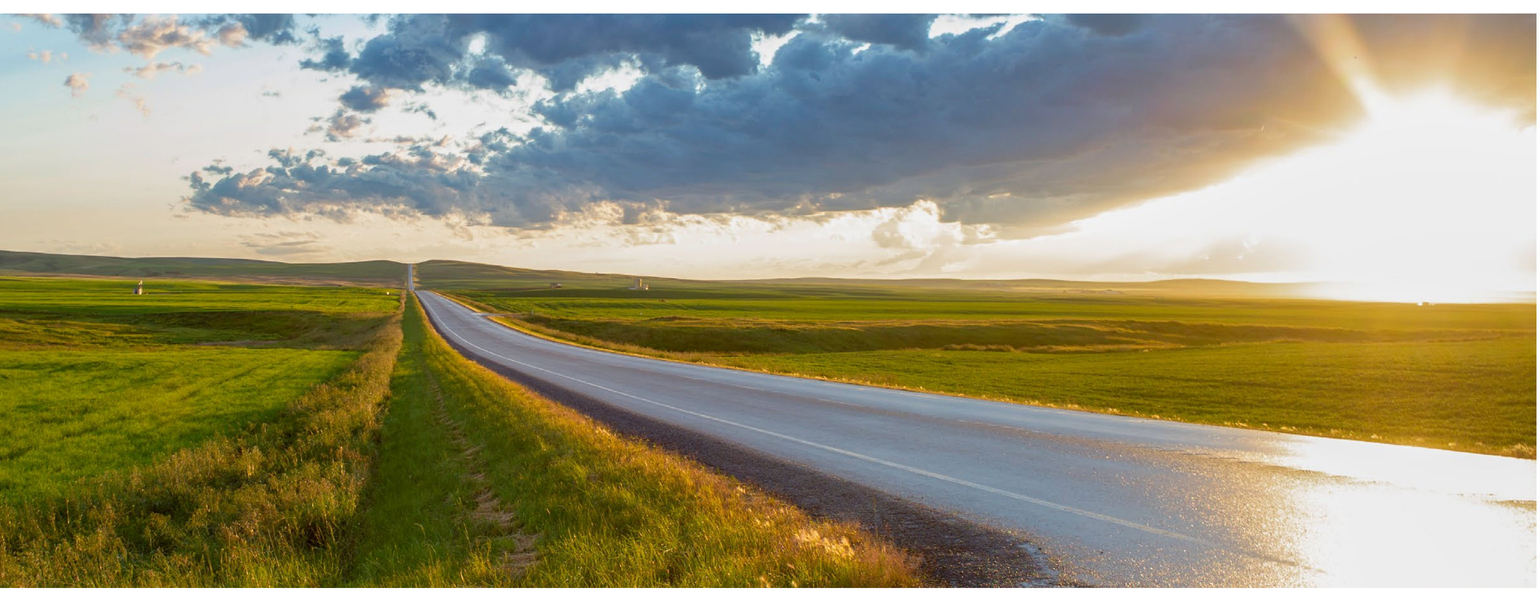
In the second interlocutory application, Ecojustice sought an injunction to stay the inquiry until the judicial review application could be heard, citing numerous procedural grounds for its application. The Court applied the test from *RJR-MacDonald Inc. v. Canada (Attorney General)*, and found that there was no clear evidence of irreparable harm to Ecojustice's reputation that would ensue if the injunction was not granted (as Ecojustice alleged), and the application therefore failed.

> **Both the judicial review decision, and depending on the outcome, the report of the Commissioner, will be interesting reading for everyone involved in the Alberta energy sector in 2021.**

ALEXIS V. ALBERTA (ENVIRONMENT AND PARKS), 2020 ABCA 188

In another post-*Vavilov* decision, the Alberta Court of Appeal considered a situation where an administrative decision maker was not required to provide reasons for her decision, and did not.

In *Alexis v. Alberta (Environment and Parks)*, the Applicant asked a Director under the *Environmental Protection and Enhancement Act* (the "**Act**") to order an environmental impact assessment report after the Director had declined to do so. The Applicant took the position that this was required under the terms of the Act. However, the Director



replied that under the circumstances it was a discretionary matter, and that no order would be made. An application for judicial review at the Court of Queen's Bench was dismissed.

On appeal, the parties agreed that the standard of review applicable to the Director's decision was reasonableness. The requirement to provide reasons was not in dispute, but given that no reasons were provided, the Court undertook its own statutory interpretation to resolve the matter. The majority held that the Director's decision was irrational and unreasonable. Given that there was only one reasonable solution, it made no sense to remit the matter back to the Director, so the Court instructed the Director to order that an environmental impact assessment report be submitted.

The most interesting aspect of this decision is the Court's determination that there was only one reasonable outcome, and not returning the matter back to the original decision maker for an ultimate decision. Historically, courts have rarely taken that approach. Indeed, in this case, the partially dissenting judge would have remitted the matter back to the Director.

This case shows that deference has limits. If it can be credibly argued that there is only one reasonable result, and particularly if a court does not have reasons for the decision it being tasked with reviewing, the court may be willing to substitute its own interpretation, even in a reasonableness review. This can be a powerful remedy.

Ontario

ROGERS COMMUNICATIONS CANADA INC. V. ONTARIO ENERGY BOARD, 2020 ONSC 6549

Any organization subject to Ontario Energy Board ("**OEB**") regulation should take heed of a November 2020 court decision that affirms the OEB's broad scope to determine its own procedures.

The challenge was made by a group of telecom companies (the "**Carriers**") who are charged standard rates for attaching their cables to electricity poles in Ontario. The Carriers sought to quash a report in which the OEB increased the default charge from $22.35 per pole per year, established in 2005, to $43.63.

Updating the fee was part of a "comprehensive review" by the OEB, in which it received input from a limited stakeholder group, issued a draft report for comment, and subsequently issued a final report.

The Carriers challenged the report before the Ontario Divisional Court. They argued they had been caught off guard by the fee increase and they had expected that a full hearing would take place before any such determination.

On this basis, the Carriers argued that the OEB's procedure was unfair.

The Court dismissed the Carriers' appeal. Although the court acknowledged that the Carriers "may not have expected" that the policy review would have resulted in a new default charge, the OEB was nevertheless on solid ground.

The Court gave the OEB a wide berth in managing the policy review and its outcomes, stating that "[d]eference applies to the decision of the [OEB] as to the process it adopted to conduct the policy review."

> **As a result, organizations should not assume that their procedural expectations – even if based on past practices – can be relied upon. Those who do not pay careful attention to a particular OEB process and its potential outcomes will do so at their peril.**

HYDRO ONE NETWORKS INC. V. ONTARIO ENERGY BOARD, 2020 ONSC 4331

After a years-long dispute with the OEB regarding the allocation of substantial tax savings, Hydro One has scored a notable victory at the Ontario Divisional Court.

The ruling handed down in July 2020 effectively means that the benefit of $2.6 billion in tax savings will flow to its shareholders, rather than to ratepayers.

In 2015, Hydro One underwent an initial public offering, at which time the government of Ontario sold its majority stake in the company. This caused Hydro One to lose certain tax privileges and resulted in a $2.25 billion "departure tax" bill, which the company funded with a pre-IPO stock sale.

The change also allowed Hydro One to increase the value of certain assets by $9.7 billion. This in turn allowed for higher tax deductions, which resulted in savings that the utility planned to pass on to its shareholders. The OEB disagreed and determined that 38% of the savings should go to ratepayers (in the form of lower electricity rates), but failed to explain what methodology it was relying on in making this determination.

Hydro One appealed to the Ontario Divisional Court, arguing that since the OEB found that the departure tax was a real cost to Hydro One, the only reasonable decision possible was that the utility's shareholders were entitled to all of the tax savings.

The Court allowed the appeal and agreed with Hydro One, stating that the OEB applied the wrong legal test and that its decision "lacks an internally coherent and rational chain of analysis." The court applied a "correctness" standard, which means little or no deference given to the OEB in this particular instance. The Court confirmed that the new approach arising from the Supreme Court of Canada's *Vavilov* decision applies to statutory appeals from the OEB, effectively making it easier to challenge the OEB where a right of appeal exists. However, the Court in this case noted it would still have found against the OEB even if the more deferential "reasonableness" standard had applied.

The matter was ordered to be brought back before the OEB to make "an appropriate order varying the tax savings allocation."

Although regulatory bodies like the OEB are often entitled to significant deference (making their decisions difficult to overturn), this case serves as an example of where a poorly reasoned regulatory decision combined with a statutory right of appeal worked strongly in favour of the utility.

> **Organizations subject to regulatory oversight should therefore pay close attention to the particular legal context of a decision in determining whether it is more cost effective to challenge a regulator's decision or to cut one's losses.**

McCarthy Tétrault represented Hydro One before the OEB and the Divisional Court.

NATION RISE WIND FARM LIMITED PARTNERSHIP V. MINISTER OF THE ENVIRONMENT, CONSERVATION AND PARKS, 2020 ONSC 2984

A decision from the Ontario Divisional Court is offering some welcome clarity to organizations concerned about risk and uncertainty arising from changes in government and public policy.

In May 2020, the Nation Rise saga met a critical juncture when the Court found that the Minister of Environment, Conservation and Parks' revocation of the Renewable Energy Approval ("**REA**") for the Nation Rise Wind Farm was both unreasonable and failed to meet procedural fairness requirements.

The Minister's decision to revoke the Nation Rise REA landed in December 2019, more than a year after the project had been approved and when the 100 MW wind farm was already well under construction.

The decision was based on submissions from Nation Rise and from an opposing community group, which had appealed from a decision of the Environmental Review Tribunal ("**ERT**") upholding the REA.

Although the Minister found the ERT decision to be "thorough and well reasoned", he decided that the wind farm could cause "serious and irreversible" harm to bat maternity colonies. Notably, such colonies had not been at issue before the ERT and were not raised by either party on appeal to the Minister.

Nation Rise appealed to the Divisional Court.

The Court sided with Nation Rise, finding that the Minister had unreasonably concluded that he had authority to add new issues – namely the issue of bat maternity colonies – on the appeal. He had applied the wrong legal test by using the precautionary approach which differed from the legislative requirement.

Moreover, the procedure adopted by the Minister was unfair in that he failed to notify the parties that the issue of bat maternity colonies would be an issue on appeal, and failed to provide a separate hearing with respect to the appropriate remedy after a decision was issued.

As a result of the disruption caused by the Minister's revocation, the Independent Electricity System Operator ("IESO") granted Nation Rise an extension on its required commercial operation date. In November 2020, the IESO stated that the project was entitled to force majeure relief since the Minister's decision was an event outside of its control.

The new milestone date is June 17, 2021.

GRASSHOPPER SOLAR CORPORATION V. INDEPENDENT ELECTRICITY SYSTEM OPERATOR, 2020 ONCA 499

If you are in the business of developing or financing power projects in Ontario, a recent Court of Appeal decision may change the way you look at contractual completion dates, as well as your ability to rely on the statements of a counterparty.

Grasshopper Solar entered into a series of standard form feed-in tariff ("**FIT**") contracts with the IESO in August 2016. The contract required Grasshopper to achieve "Commercial Operation" of the facility by a specified date (the "**Milestone Date**"). While it provided in s. 2.5(a) that "time [was] of the essence" for this obligation, it addressed termination rights separately under the detailed provisions of Article 9. Section 9.1(j) permitted the IESO to terminate if Commercial Operation was delayed, but only if Grasshopper did not achieve Commercial Operation within 18 months after the Milestone Date. Section 9.1(b) also permitted the IESO to terminate for any "material" default, but it was subject to prior expiry of a 15 to 30 day cure period, and contained a carve-out for events of default that were already addressed separately in Article 9, as under s. 9.1(j).

At the time of the FIT contract, there was an existing IESO bulletin from 2013 (the "**Bulletin**") stating that if a FIT contract holder could not achieve Commercial Operation by the Milestone Date, the IESO would not exercise its purported termination right in s. 9.1(b). The Bulletin also contained technical qualifying language stating that it did not constitute a waiver and should not be relied on by suppliers.

In March 2019 – 2.5 years into its FIT contract – Grasshopper received a letter from IESO informing Grasshopper that the IESO was retracting the Bulletin and that the FIT contracts would be terminated under s. 9.1(b) if Grasshopper did not achieve Commercial Operation by the Milestone Date, which by then was only 6 months away, a deadline that was virtually impossible to meet. The IESO's change in position came 9 months after the election of the Progressive Conservative Party in Ontario, which had campaigned on a platform that was hostile to the previous Liberal government's clean energy program.

Grasshopper applied to the Ontario Superior Court for a declaration that the IESO could not terminate for Grasshopper's failure to achieve Commercial Operation by the Milestone Date unless Commercial Operation was still not achieved 18 months after the Milestone Date. In essence, it argued the IESO could not exercise its general termination right in s. 9.1(b), because the failure to achieve Commercial Operation by the Milestone Date was an event of default already dealt with separately in s. 9.1(j), where it was subject to an 18-month cure period rather than the 15 to 30 day cure period in s. 9.1(b). In addition, Grasshopper argued that the IESO was estopped from terminating the FIT contracts on this basis given the Bulletin and the IESO's lengthy pattern of conduct in applying it, which created a mutual assumption that that Grasshopper relied upon to its detriment.

Grasshopper was unsuccessful before the Ontario Superior Court, as well as before the Ontario Court of Appeal. The courts held that because s. 2.5(a) of the FIT contract said that time was of the essence in respect of Grasshopper's obligation to achieve Commercial Operation by the Milestone Date, the failure to do so was necessarily an event of default that engaged the IESO's termination right in s. 9.1(b), regardless of whether it was dealt with separately in s. 9.1(j). The courts also found that there was no mutual assumption that the IESO would not exercise its termination right in s. 9.1(b) for the failure to achieve Commercial Operation by the Milestone Date, so as give rise to estoppel, because the qualifying language in the Bulletin left the IESO free to change its position and the March 2019 letter was reasonable notice of its intent to do so. The courts were not swayed by the serious economic consequences to be faced by Grasshopper by virtue of the IESO's change in position.

Prior to this decision, the general view in the industry was that missing a Milestone Date in a standard FIT contract was not an event of default that could lead to termination. That assumption may no longer be viable, which should be of concern to project proponents and lenders alike. More generally, the decision serves as a cautionary tale when contracting with a counterparty, whose position may change over time due to shifting government policies.

McCarthy Tétrault represented Grasshopper before the Court of Appeal. There is presently an application for leave to appeal pending before the Supreme Court of Canada.

Quebec

RIVARD C. ÉOLIENNES DE L'ÉRABLE, 2020 QCCS 601

This is Canada's first ever class action decision on the merits involving a wind project developer and its wind farm. It confirms that the installation of wind turbines in a settled area does not per se give rise to liability for damages resulting from abnormal neighborhood disturbances.

In 2008, Hydro-Québec selected the wind power project proposed by Enerfin (now Éoliennes de l'Érable) to install 50 wind turbines, for a total capacity of 100 MW in rural areas situated in the Centre-du-Québec region.

The class action was instituted on behalf of the residents of that area who were claiming damages for the annoyances associated with the construction and the operation of the wind farm based on the Civil Code of Québec, which provides for a "right to nuisance", as long as it does not exceed the threshold of tolerance required in a given context. Only annoyances with a certain level of recurrence and gravity will be considered as abnormal within the meaning of that article.

The Superior Court first rejected the class members' claim that the alleged annoyances of truck traffic, schedules of work, road closures, detours, use of engine brakes, dust and noise constituted abnormal neighborhood annoyances during the construction phase. The Court noted that the defendant had taken a number of measures to limit the annoyances and to maintain an effective collaboration with the municipality.

Importantly, the Superior Court also held that a reasonable person could hear the wind turbines noise without being disturbed, and that the wind turbines complied with the noise limit set by the decree approving the project, thus rejecting the members' claim pertaining to the operation phase. Finally, the Court held that the members could not be compensated for the loss of visual appearance due to the presence of the wind turbines.

The class members filed an appeal in September 2020, and the appeal is expected to be heard in 2021.

ATTORNEY GENERAL OF QUÉBEC V. IMTT-QUÉBEC INC., 2019 QCCA 1598

In April 2020, the Supreme Court of Canada dismissed an application by the Attorney General of Quebec to appeal a judgment rendered by the Québec Court of Appeal in September 2019. The decision may be of interest to any energy company carrying out federally-regulated activities and seeking environmental permits in any province, as it confirms the inapplicability of certain provincial environmental requirements with respect to such activities.

IMTT-Québec Inc. ("**IMTT**") is a federally-incorporated company that handles and stores bulk liquid products (including petroleum, heating oil, jet fuel, oils and lubricants, ethanol, methanol and biodiesel) in large tanks on federal property that it leases from the Québec Port Authority. IMTT's customers rent these tanks to transport the various products delivered to the Port of Québec (mainly by ship). In 2006, IMTT decided not to seek provincial authorization when it began planning new tank construction projects to increase capacity, claiming it was a company under federal jurisdiction not subject to the *Québec Environment Quality Act* ("**EQA**"), and rather sought and obtained authorization from the Québec Port Authority and federal authorities. IMTT and the Québec Port Authority sought a declaration that the EQA's authorization scheme was either inapplicable or inoperative with regard to IMTT's federal activities within the Port of Québec.

The Court of Appeal held that provincial environmental authorization mechanisms cannot apply to projects under exclusive federal jurisdiction; rather, they must be tied to projects falling under provincial heads of power. Therefore, EQA's discretionary authorization scheme could not apply to IMTT's activities, as they take place on property belonging to the federal Crown and are closely integrated with navigation and shipping, which both fall within federal heads of power.

The Court of Appeal also upheld the trial judge's conclusion that the EQA's environmental authorization scheme was constitutionally inoperative with respect to IMTT's activities pursuant to the doctrine of federal paramountcy, which applies where there is an operational conflict between a valid provincial law and a valid federal law, or where the provincial statute frustrates the purpose of the federal legislation.

McCarthy Tétrault successfully represented the Québec Port Authority and IMTT in this matter.

HYDRO-QUÉBEC V. MATTA, 2020 SCC 37

In this unanimous decision, the Supreme Court of Canada found that nothing prevented Hydro-Québec from building a new electricity line to be routed in part through private lots on which Hydro Québec already had servitudes (known as "easements" outside of Quebec) established for another electrical transmission line.

In 2015, Hydro-Québec received authorization to construct an electrical transmission line between a transformer substation in Saguenay-Lac-St-Jean and another one in Montréal. Hydro-Québec realized that it would be easier to run the line through a corridor where it already had servitudes that had been established in the 1970s for a distinct transmission line. Hydro-Québec claimed that these servitudes authorized it to route up to three electrical transmission lines but the current owners of the lots submitted that the rights arising from the servitudes were limited to the existing line only and denied Hydro Québec's employees access to their lots.

> **The Supreme Court held that the servitude agreements in this case were not ambiguous, and therefore that the scope of the servitudes had to be determined in light of the words used in the agreements.**

As there was no mention of any restrictions regarding the origin or the destination of the electricity, the Court concluded that the servitudes were not limited to the existing line. The Court added that the servitudes concerned the lines crossing the servient land, not the substations located at either end of those lines, thus nothing in the words of the agreements explicitly or implicitly prevented Hydro-Québec from redirecting one of its lines toward another substation.

RESOLUTE FP CANADA INC. V. HYDRO-QUÉBEC, 2020 SCC 43

In 1926, the corporate predecessor of Resolute FP Canada Inc. ("**Resolute**"), a forest products company, and the Gatineau Power Company ("**Gatineau Power**"), a private electricity producer, signed a contract for the supply of electric power which provided that Resolute would accept any increases in the price of electricity that might result from future increases in taxes or charges levied by the provincial or federal government on electrical energy generated from water power. In the early 1960s, during the phase of the nationalization of electricity, Gatineau Power became a wholly owned subsidiary of Hydro-Québec. In 1965, Hydro-Québec entered into a contract with Gatineau Power to unify Gatineau Power's management and operations and to provide for the sale of all of Gatineau Power's movable assets to Hydro-Québec and the lease of all of the Gatineau Power's real estate for a term of 25 years to Hydro-Québec.

Starting in 2007, Hydro-Québec had two new levies imposed on it under provincial legislation. Relying on the price adjustment clause in the 1926 contract, Hydro-Québec sent Resolute an electricity bill for over $3 million in 2011, claiming from Resolute an increase in the price of electricity that resulted from the levies it paid to the Québec government. Resolute paid this bill under protest and asked the Superior Court to declare that it did not owe the amount being claimed from it to either Hydro-Québec or Gatineau Power.

> **In this 7-2 decision, the majority held that the 1965 contract effected an assignment of the 1926 contract and as a result, that Hydro-Québec was a party to the 1926 contract and can therefore invoke it against Resolute.**

The majority therefore rejected Resolute's argument that the 1965 contract merely made Hydro-Québec a mandatary of Gatineau Power for purposes of managing the 1926 contract. Because the two levies at issue were a "tax or charge" on electricity generated from water power within the meaning of the 1926 contract, the majority concluded that they were therefore payable by Resolute to Hydro-Québec under that agreement.

SMRs: Canada Places a Bet that its Future Could be Nuclear

Authors: Audrey Bouffard-Nesbitt, Stephen Furlan, Emma Holmes and Seán O'Neill

In 2020, efforts continued to carve out a place in Canada's energy sector for small modular reactors ("**SMRs**"). SMRs are an emissions-free, reliable and readily deployable distributed generation baseload technology that is lauded as a key piece of the puzzle to help achieve federal, provincial and territorial decarbonization targets, as well as address numerous energy challenges arising from Canada's geography, load requirements and international commitments. These efforts include the federal government's launch of the *Small Modular Reactor Action Plan* (the "**Action Plan**") in December 2020, as well as steps taken by certain provincial governments and industry players to promote and advance SMR technology in Canada. With a potential export market of $150 billion per year, the federal government is tantalized by the great economic opportunity that SMRs present. Unsurprisingly, Canada is not alone in its efforts to develop SMRs; the global race to bring the first commercially viable SMR technology to market is highly competitive. Key players, such as the US, the UK, Russia and China, have committed substantial government funding and made significant advancements in SMR technology to date.

The Action Plan

On December 18, 2020, Canada's Minister of Natural Resources, Seamus O'Reagan, released the Action Plan to build on Natural Resources Canada's 2018 publication '*A Call to Action: A Canadian Roadmap for Small Modular Reactors*' (the "**Roadmap**"). The Action Plan responds to the Roadmap's recommendations with a statement of seven principles. These principles will guide Canada in the development, demonstration and deployment of SMRs to benefit Canadians economically, environmentally, geopolitically and socially. 109 organizations from across Canada participated in the Action Plan, including the federal government, provinces and territories, Indigenous Peoples and communities, power utilities, industry, innovators, laboratories, academia and civil society. All of the participants endorsed the Action Plan's statement of principles and contributed a chapter to the Action Plan. These chapters detail the actions that participants are taking, or plan to take, to further Canada's goal of being a global leader in SMR technology.

The Action Plan endorses nuclear energy, and SMRs in particular, as being key to helping Canada and the rest of the world achieve a low-carbon future. Canada has committed to reducing its greenhouse gas emissions under the *Paris Agreement* and to retiring all coal-fired power generation by 2030. An even loftier goal was set out with the tabling of Bill C-12, the *Canadian Net-Zero Emissions Accountability Act, in November 2020* ("**Bill C-12**"). Bill C-12 aims to legislate Canada's pledge of achieving net-zero greenhouse gas emissions by 2050. In order to achieve these targets, Canada's energy mix must shift away from carbon-emitting energy sources.

The integration of renewable energy sources with SMR technology could be part of the solution to achieving these emissions targets. As renewable energy sources such as wind and solar are not available on demand, another source of energy is required to ensure reliable power. Zero-emissions load-following resources ("**ZELFRs**") can fill the gaps in variable renewable energy supply by adjusting their output based on fluctuations in demand, providing a continuous, reliable and non-emitting source of energy. Innovations in Generation IV reactor technology are predicted to allow SMRs to be an extremely promising ZELFR, considering its potential commercial viability and rapid load-following capability. Generation IV reactors are the primary focus of SMR development and six Generation IV reactor technologies are currently being researched by the Generation IV International Forum (the "**GIF**"). The six technologies that the GIF is researching were selected on the basis of their potential as clear, safe and cost-effective means to sustainably increase energy supply, while being resistant to materials diversion for weapons proliferation and being secure from terrorist attacks. The GIF is a co-operative international endeavor, in which Canada is a participant, that seeks to research and test the feasibility of Generation IV technology.

Canadian Technology and Funding Updates

A necessary first step in SMR development, buy-in from Canadian political leadership, gained additional critical mass in August 2020 when Alberta Premier Jason Kenney announced that Alberta would sign the inter-provincial memorandum of understanding (the "**SMR MOU**") to advance the development and deployment of SMRs, along with addressing climate change, regional energy demand, economic development and research and innovation technologies. Alberta will be the fourth province to join the SMR MOU, which was entered into by Saskatchewan, New Brunswick and Ontario on December 1, 2019.

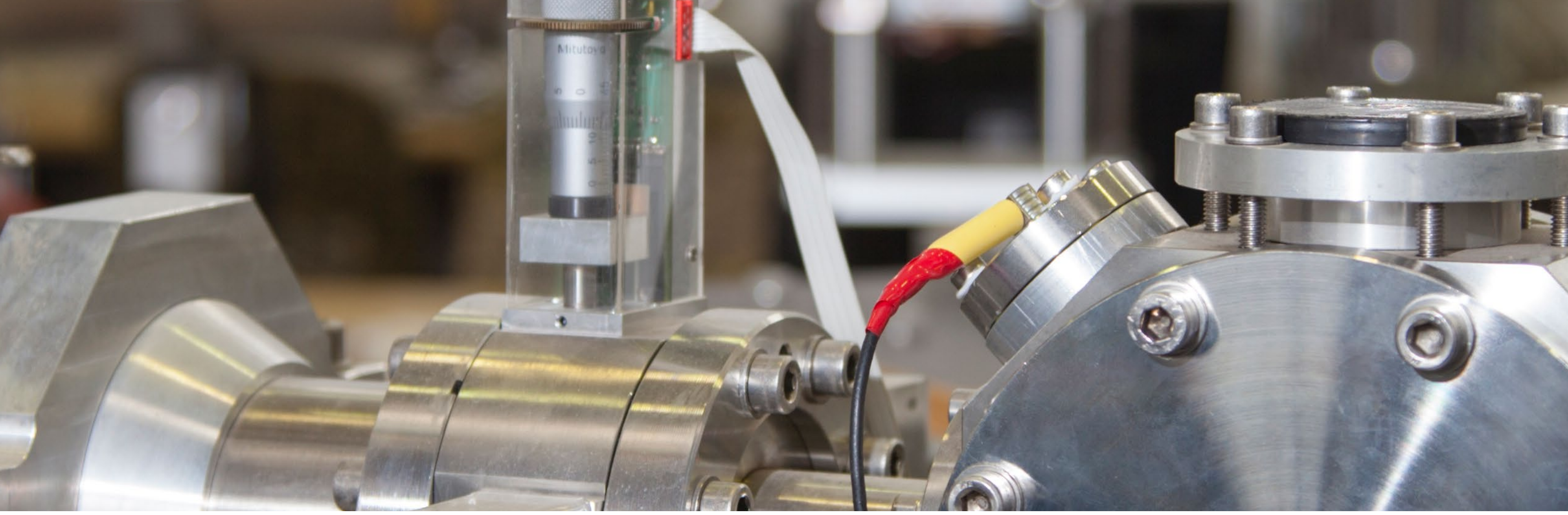
As a result of the SMR MOU, the CEOs of the major electricity utilities in Ontario, New Brunswick and Saskatchewan, including Bruce Power, Ontario Power Generation ("**OPG**"), New Brunswick Power ("**NB Power**") and SaskPower (collectively, the "**CEO SMR Forum**"), are collaborating to achieve industry alignment on the development and deployment of SMRs in Canada. The CEO SMR Forum has been developing three streams of SMR projects to be developed in parallel with equal priority:

1 **Stream 1 will reduce carbon emissions and create growth opportunities for communities connected to the grid ("Stream 1");**

2 **Stream 2 will support the advancement of nuclear technology and innovative methods to reduce nuclear by-products ("Stream 2"); and**

3 **Stream 3 will bring affordable, clean energy to remote communities and mines ("Stream 3").**

In furtherance of Stream 1, Bruce Power, SaskPower and OPG are collaborating to determine the feasibility of grid-scale connected SMR technology and to determine the optimal technology option for Canada. OPG proposes to build a first-of-a-kind grid-scale SMR of approximately 300-400 MW at its Darlington Nuclear Power Station, with a targeted start up date in 2028. Following the successful deployment of the SMR technology at Darlington, SaskPower is evaluating the economic and technical feasibility of deploying 300 MW of generating capacity from SMRs by 2032, with the potential for a further 900 MW between 2035 and 2042. On October 6, 2020, OPG announced that it is advancing engineering and design work on the project with three developers:



GE Hitachi Nuclear Energy, a US based US-Japanese collaboration, Terrestrial Energy, an Ontario developer, and X-Energy, a US developer. The Canadian Nuclear Safety Commission's ("**CNSC**") vendor design review ("**VDR**") of Terrestrial Energy's Integral Molten Salt Reactor ("**IMSR**") began in 2016 and is expected to be completed in 2021. GE Hitachi Nuclear Energy submitted two packages to the CNSC for the VDR of its BWRX-300 SMR in January 2020, and X-Energy submitted its scalable 80MWe Xe-100 SMR to the CNSC for VDR in July 2020.

New Brunswick has taken the lead on Stream 2. In November 2020, NB Power, Moltex Energy, a UK company ("**Moltex**") and Advanced Reactor Concepts (the parent company of ARC Nuclear Canada Inc., "**ARC Canada**") announced that they signed a memorandum of understanding to establish a SMR vendor cluster in New Brunswick and to advance Generation IV grid sized SMR technology. This memorandum of understanding follows the New Brunswick government's $10 million investment in ARC Canada and Moltex in 2018 to assist in the development of their advanced Generation IV SMR designs. ARC Canada's ARC-100 design, a sodium-cooled fast reactor, and Moltex's SSR-W design, a Stable Salt Reactor – Wasteburner, are expected to be demonstrated at the Point Lepreau Nuclear Generation Station in the early to mid 2030s. It is worth noting that Moltex has also received financial support from the UK and US governments.

Stream 3 projects involve micro SMRs that can be used to displace diesel generation currently used in remote areas for mining and in northern remote communities for heat and electricity generation. On June 9, 2020, OPG announced its partnership with Ultra Safe Nuclear Corporation, a Seattle-based technology company, on a joint venture called Global First Power. The project proposes to build a first-of-a-kind 15 MW thermal micro modular reactor at Chalk River Laboratories. The project is Canada's first SMR with an active Environmental Assessment and CNSC license application. The project has announced it is on track to deliver Canada's first SMR installation in early 2024. In October 2020, Bruce Power announced its collaboration with Westinghouse Electric Company ("**Westinghouse**") to determine the feasibility of Westinghouse's eVinci micro reactor in Canada and potential applications and frameworks for deployment. Westinghouse submitted the eVinci micro reactor to the CNSC for VDR in 2018.

On October 15, 2020, the federal government announced a $20 million investment in Terrestrial Energy through the Strategic Innovation Fund. The investment will allow Terrestrial Energy to accelerate the development of its Generation IV technology as part of the company's IMSR project. Terrestrial Energy's chapter in the Action Plan indicates that its first commercial IMSR is on track to supply electric power to the grid by 2028.

The Global Race to Achieve Commercially Viable SMR Technology

Canada was not alone in making efforts in 2020 to further the development of commercially viable SMR technology. Many countries, including the US, UK, Russia, China and Argentina, made technological advances and increased their funding of SMR projects in the hopes of being the first to market in order to set the global standard in SMR technology.

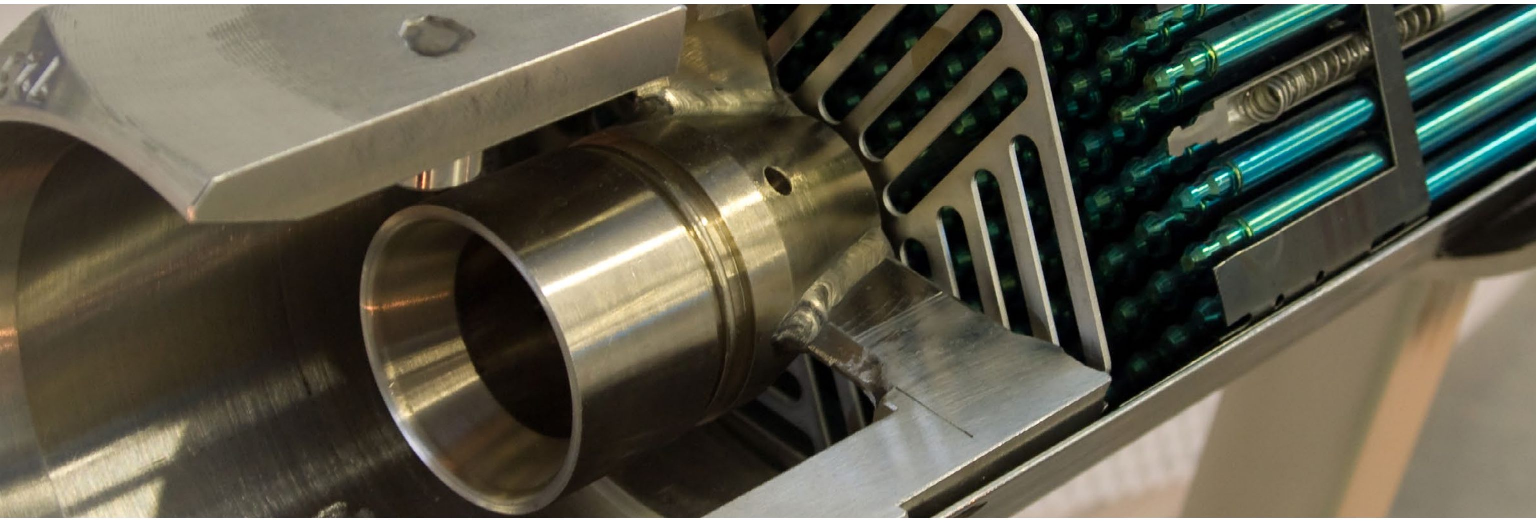
On October 16, 2020, the US Department of Energy ("**DOE**") awarded USD $1.355 billion to the Utah Associated Municipal Power Systems ("**UAMPS**") owned Carbon Free Power Project, formally launched in 2015 in partnership with Portland based NuScale Power. The investment is intended to further the development of a potential 720 MW SMR plant to be located in Idaho. This DOE award follows the $16.6 million cost-shared funding provided by the DOE to UAMPS and NuScale Power in 2015. Construction of the plant is scheduled to begin in 2025, with the first module expected to be operational in 2029. NuScale Power achieved a significant milestone in August 2020 by receiving the first SMR approval issued by the Nuclear Regulatory Commission.

UK Prime Minister Boris Johnson announced in November 2020 that the UK government would be investing up to £215 million in SMR development through the UK SMR consortium, to be delivered as part of UK Research and Innovation ("**UKRI**"). This investment follows the £18 million invested by UKRI in the consortium in November 2019. The consortium's program is scheduled to enter its next phase of development in May 2021, which aims to raise an additional £300 million to deliver a fully-engineered and fully approved product.

Russia, China and Argentina appear to have the most advanced technologies. Russia's Akademik Lomonosov is the world's first floating nuclear plant and the first nuclear power plant based on SMR technology to generate electricity. The plant has been connected to the grid and began commercial operation in May 2020. The plant was developed by Rosatom, a Russian state nuclear energy corporation, and is hoped to be a breakthrough for providing sustainable power to the Arctic and other remote, hard-to-reach areas all over the world. Russia is also developing a land-based SMR project that is scheduled to be operational in 2027. One of China's SMR designs is HTR-PM, an industrial demonstration in the advanced stages of construction. The SMR is scheduled to begin power generation later this year. Argentina's CAREM SMR prototype is also in advanced stage construction, with operations scheduled to begin in 2023.

The Future of SMRs in Canada

SMR technology holds the potential to help Canada achieve its net-zero emissions target by 2050. The potential of SMR technology has been recognized globally, as 72 reactors are in development in 18 countries, with efforts taken during 2020 to advance the commercial viability of SMR projects globally. Canada is well-positioned to be a global leader in this industry, using its almost 80 years of nuclear energy expertise to guide the development of its SMR projects. However, the competition is intense from both international SMR technologies and alternative existing and developing low-emission energy generation technologies. Canadian champions will need sustained government support of SMR projects, patient venture capital and public acceptance to displace other forms of new or incumbent domestic energy production and to provide a domestically produced SMR solution in Canada that can compete on the world stage.



Energy Storage: a Key to Energy Transition

Authors: Reena Goyal, Kimberly Howard, Kerri Lui, Suzanne Murphy, Jason Phelan, Suleiman Semalulu and Christopher Zawadzki

Introduction and overview of the technology

Electricity markets are beginning to experience a rapid transformation as development and deployment of energy storage continue to grow at an accelerated rate. While industry stakeholders have been aware of potential benefits for some time, energy storage now appears to be at an inflection point. The current rise of energy storage financing and development opportunities mirrors the heightened interest in solar technologies that we observed nearly a decade ago.[7]

Storage technologies present a unique opportunity to more precisely balance the supply and demand of electricity in a reliable, affordable and sustainable manner. Energy storage refers to the process of converting electrical energy to a storable form and then back into electricity when required. The term "energy storage" is a broad umbrella that applies to a range of technologies and applications.

Technologies can be loosely be classified into the following four categories based on the form of energy stored or the method of energy conversion: (1) mechanical; (2) electrochemical/electrical; (3) thermochemical and (4) thermal. Technologies within these categories differ significantly in a number of ways, including cost, scalability, maturity, efficiency, end-use applications and other characteristics. Certain technologies, such as pumped hydroelectric, are mature technologies with a proven track record of implementation and operation. Other technologies, such as certain forms of battery storage or fuel cells, are more novel with less cost and performance certainty. Each specific technology presents a unique set of benefits and advantages with respect to development and wider integration.

7 In recognition of this development, McCarthy Tétrault LLP and DNV GL co-hosted a webinar on energy storage fundamentals in November 2020. Leading experts from both organizations presented on the topics of technology basics, market and regulatory evolution and opportunities, and contracting and financing issues.

Category	Process & Primary Applications	Pros & Cons
Pumped Hydroelectric	The system consists of two vertically separated water reservoirs. During off-peak periods, surplus electricity is used to pump water into the higher level reservoir. During peak periods, water is released back into the lower level reservoir powering turbine units connected to electricity generators. Time shifting.	**Pros:** large energy capacity potential; high adoption rates; 70-80% cycle efficiency; long life expectancy. **Cons:** long construction lead times; high capital investment; specific site requirements (such as close proximity to large reservoirs)
Compressed Air	During off peak periods, surplus electricity drives a reversible motor or generator which injects air into a storage vessel. During peak periods, the stored compressed air is released, heated, then captured by turbine units connected to electricity generators. Black start power to nuclear units, back up to local power systems and extra electrical power to fill gaps between generation and demand; Load shifting; peak shaving; and voltage control.	**Pros:** 91.2-99.5% starting and running reliability; technology is extremely flexible in terms of capacity sizes (the power output from a single unit can be in excess of 100MW). **Cons:** limitations in terms of appropriate geographical locations.
Battery Energy	A number of electrochemical cells connected in series or parallel that produce electricity with voltage from an electrochemical reaction. Power quality; energy management; ride through power; transportation systems.	**Pros:** mature technology; high rate of integration and adoption. **Cons:** low cycling times; high maintenance costs; disposal concerns.
Hydrogen Storage and Fuel Cells	Water electrolysis is used to produce hydrogen stored in high pressure containers or transmitted by pipelines for later use. Fuel cells are used to generate electricity from stored hydrogen. Fuel cells convert chemical energy in hydrogen and oxygen into energy, thereby releasing electrical and heat energy. Used for energy storage, wind power, and fuel for transportation.	**Pros:** quiet; less pollution; compact design and easy scalability. Fuel cell systems can also be combined with hydrogen production and storage to provide distributed power and transportation power. **Cons:** high costs; disposal issues.

In terms of scale, energy storage projects are often categorized into "behind the meter" and utility scale, "front of the meter" projects. The former is typically used to reduce power costs and usage for residential or commercial loads. The latter will usually involve a power contract for voltage control or ancillary services with a governmental authority (such as the IESO) or a local distribution company or the direct sale of electricity into the commercial market. A third category of energy storage projects involves the integration of an energy storage facility with a more traditional generation facility (e.g. wind or solar) to mitigate the intermittent nature of certain renewable power sources.

Energy storage presents a number of direct and indirect benefits for the electricity system. Unlike more traditional power technologies that typically offer a limited range of services, energy storage technologies can provide multiple services and applications across the electrical system. For example, energy storage technologies can act as a load and as a generator to provide balancing services and fill in capacity shortfalls during spikes in electricity usage. Broader implementation of energy storage may facilitate deeper integration of renewables into the power grid by mitigating the intermittent quality of such energy generated from renewable sources. Energy storage can also improve the reliability, safety and security of the electricity grid through enhanced control of fluctuating voltage and frequency.

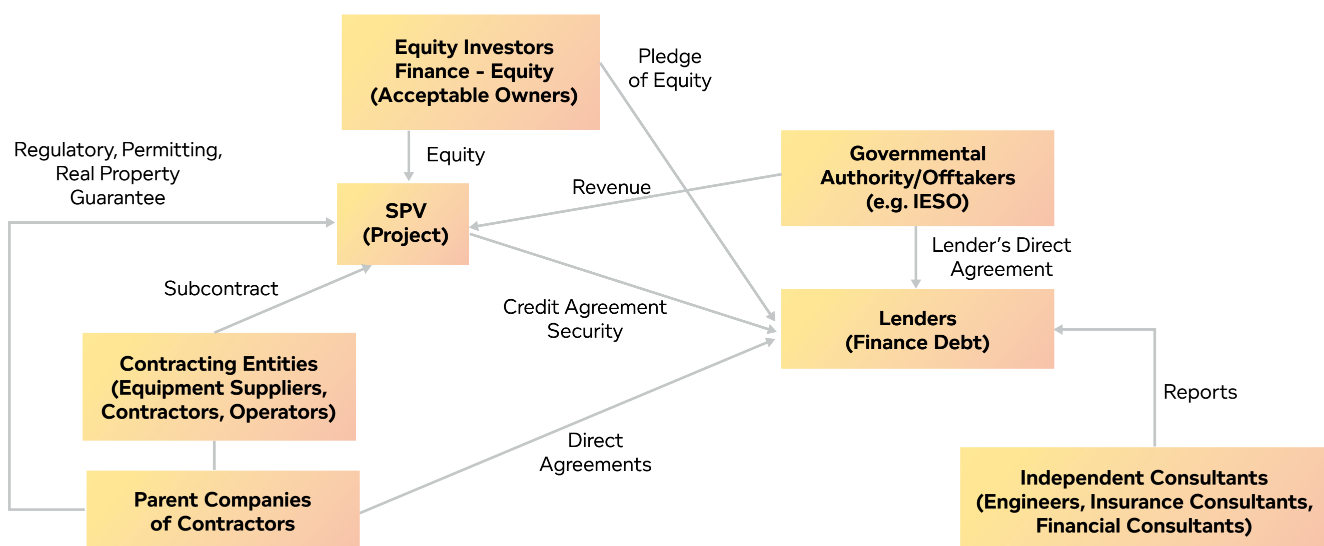
Legal Structure of an Energy Storage Project and Legal Issues to Consider

LEGAL STRUCTURE OF AN ENERGY STORAGE PROJECT

The contracts that will be entered into by a developer in respect of an energy storage project are generally similar to traditional renewable energy projects, as depicted in the diagram below.

Like other projects, an energy storage project is typically owned by a special purpose vehicle ("**SPV**") formed by the developer. The SPV will usually enter into a power purchase agreement (a "PPA") (sometimes referred to as a facility agreement or energy services agreement) with a creditworthy off-taker, who may be, as previously mentioned, a residential or commercial load customer (for "behind the meter" projects) or a governmental authority or local distribution company (for "front of the meter" projects). If the project is being built on land that is not owned by the developer, the SPV will need to enter into customary real property agreements to obtain the requisite real property rights (e.g. a lease or license) and ensure that it has all necessary access rights to the project.

For the construction phase of the project, the SPV will typically enter into an engineering, procurement and construction agreement with a contractor. These agreements will often provide for the procurement of project equipment by the contractor (rather than the SPV or developer directly entering into separate equipment supply agreements, which is a common approach for traditional renewable energy projects). Depending on the in-house capabilities of the developer, the SPV may also enter into operation and maintenance ("**O&M**") agreements and asset management/dispatch agreements with third parties.



SPV: Special Purpose Vehicle
Security: Security interests in all project assets including ownership interests in SPV and material project contracts.
Sponsors sometimes require credit support in for of a guarantees or letters of credit.

RISKS OF AN ENERGY STORAGE PROJECT FROM A LENDER'S PERSPECTIVE

Although we have yet to observe any large-scale project financings for energy storage projects in Canada, we expect that such financings will substantially mirror the financing structure for renewable projects. Similar to other project financings, lenders will need to ensure the contractual matrix for the project hangs together and that there are sufficient, recurring revenues generated by the project to service debt. Lenders will assess the ability of the projects to support themselves without ongoing sponsor equity support. The SPV and the developer will be expected to grant customary security in favour of the lenders, including a pledge of the developer's equity in the SPV. As with traditional renewable project financings, lenders will expect to enter into direct agreements with the offtaker or load customer and relevant third party contractors and service providers.

Notwithstanding such similarities, certain unique features of energy storage projects distinguish energy storage financings from traditional renewable project financings. For example, given the heightened risk profile and lower degree of revenue certainty for energy storage projects, we expect that lenders may demand: (i) a lower debt to equity ratio than the standard 80/20 ratio that we are accustomed to seeing for traditional renewable energy projects; or (ii) cash sweeps to the extent that the project earns revenues that exceed the expected revenues in the financial model.

Given the novelty of certain emerging energy storage technologies, we expect that lenders will rely heavily on the input and expertise of independent engineers to assess technological risk and to ensure that the developer's maintenance plan is sufficiently robust. The expertise and creditworthiness of developers, operators and asset managers will be of particular importance for lenders.

CONTRACTUAL RISKS FROM A DEVELOPER'S PERSPECTIVE

Certain contractual risks may arise in relation to an energy storage project from a developer's perspective, including risks relating to the "host", revenue risk and guarantee risk.

Host risk arises primarily in respect of "behind the meter" projects, as such projects are typically reliant on a single load customer or "host" whose primary business is industrial or commercial in nature. The following risks may arise as a result of this reliance on a single host:

– The host could cease to operate the business or change its business operations in a way that does not allow the developer to utilize the nameplate capacity of the project. To mitigate this risk, the developer will want to ensure that its PPA provides for a termination right in favour of the developer and an obligation for the host to pay liquidated damages that reflect the revenue that would have been paid if the business change has not occurred (i.e. the remaining value of the contract).

- Insolvency risk is heightened given that the host is a corporate entity, rather than a governmental authority or energy utility.

- The host may require the site (including the project) to be shutdown for safety and maintenance reasons. The developer will want to ensure that its PPA provides adequate compensation during this period for lost revenues.

- The developer rarely has a consent right over a sale of the site by the host or a change of control of the host. While the host should not be released from its obligations, the sale could nevertheless result in a change of business operations that adversely affects the project or a new host with a different credit profile from the original host (which could result in increased insolvency risk).

- Assistance from the host will typically be required by the developer in order to obtain its interconnection and regulatory approvals. An unresponsive host may result in significant schedule delay, which may ultimately trigger termination rights under the PPA. To mitigate this issue, the developer will want any milestones under the PPA to be automatically extended for host delay.

As noted in our earlier commentary on lender risks, an energy storage project may be susceptible to significant revenue variability. For a "behind the meter" project, the developer will often receive a negotiated percentage of one or more of the following revenue streams: (i) customer savings from the operation of the facility (relating to time-of-use electricity price arbitrage or, in Ontario, savings from reduced global adjustment charges), (ii) participation in demand response programs, (iii) the sale of environmental attributes from the project in jurisdictions where those attributes have value, and (iv) if the customer is an energy utility, emergency dispatch revenue when the project is requested to provide power due to an emergency event causing electricity grid reliability concerns. This approach departs from traditional renewable PPAs where the off-taker is obligated to simply "take or pay" for power up to the contracted amount at the contract price.

The risks posed by revenue variability are heightened when combined with performance guarantees in the energy storage PPA.

It is not unusual for customers to demand that the developer guarantee a certain amount of savings from the project or guarantee certain levels of project performance or availability. If the developer agrees to provide such guarantees, the developer will need to be particularly diligent about ensuring that the project is properly maintained and that there is no degradation of performance over time. The developer should also: (i) ensure that any performance guarantees are adjusted to reflect unearned savings due to force majeure or issues caused by the host; and (ii) to the extent there is an O&M provider, pass on this risk by negotiating a back-to-back performance guarantee in the O&M agreement.

Overview of Developments in Canada

ALBERTA

Alberta's first transmission connected energy storage project was completed in September 2020. As of the date of publication, 10 additional energy storage projects are listed within the Alberta Electric System Operator's ("**AESO**") connection queue.

In August 2019, the AESO released its *Energy Storage Roadmap*, which sets out a plan to facilitate the integration of energy storage technologies into the AESO's Authoritative Documents and the AESO's grid & market systems. Highlights of the regulatory initiatives undertaken in 2020 to implement energy storage into Alberta's grid include the following:

- The Energy Storage Learnings Forum was organized to gather industry leaders to discuss and share learnings from energy storage integration in other jurisdictions. Additional consultation is expected to take place in 2021 to: (i) discuss economic modeling; (ii) share experiences in commissioning and testing of new technologies or configurations; and (iii) process efficiencies within existing frameworks.

- The AESO is currently hosting stakeholder engagement sessions on tariff treatment for energy storage with regard to the AESO's Bulk and Regional Rate Redesign. The AESO intends to file with the Alberta Utilities Commission

("**AUC**") an application for bulk and regional rate design by June 2021 with stakeholder consultation occurring in Q1 and Q2 of 2021.

- On October 1, 2020, the AESO released its *Long-term Energy Storage Market Participation Options Paper* (the "**Paper**"). The Paper discusses longer-term initiatives to address the unique aspects of energy storage integration that are not addressed within the current market rules. The AESO is hosting stakeholder engagement with the intention of releasing a long term energy storage market participation draft recommendation in Q1 2021.
- On October 14, 2020, the AESO announced that it is planning a technology pilot project targeted at any new technology that is capable of meeting the fast frequency response ("**FRR**") technical requirements. Lessons learned will be made public and will inform the Long Term FFR design and the Energy Storage Road Map. The AESO intends to run the procurement through an open process with a target of 20 to 40 MW from 1 to 3 service providers. Providers will be required to respond within 12 cycles (0.2 seconds) when a system frequency of 59.5 Hz is detected.

To assist developers, the AESO's Information Document #2020-013, *Energy Storage Guide* ("**Information Document**") provides the current AESO Authoritative Documents and ISO Rules that apply to energy storage projects. Such rules and guidance apply in the interim as the AESO works on longer term initiatives to address the unique characteristics of energy storage integration. Significant highlights from the Information Document include:

- The AESO intends that any reference to a generating source asset within the ISO Rules applies to an energy storage facility.
- Normal operating limits will be included in the applicable functional specification for the energy storage facility. Real-time stage of charge information will be provided to the AESO through Supervisory Control and Data Acquisition.
- A hybrid site is considered to be a site with a combination of an energy storage facility co-located with at least one other generating unit or aggregated generating facility that is not an energy storage facility. A pool participant of a hybrid site may choose to offer all the generating facilities on site as a single source asset; or offer each generating facility as a separately registered source asset.
- A renewable hybrid site is considered to be a site with a combination of an energy storage facility co-located with a wind or solar aggregated generating facility. A pool participant of such a site may choose to offer the energy storage facility as a source asset separate from the wind or solar aggregated generating facility; or offer all generating facilities on site as a single source asset.
- For the purposes of applying the requirements for Alberta reliability standards, a battery energy storage facility will be considered an aggregated generating facility. This means if a battery energy storage facility is installed with another aggregated generating facility and system access service(s) for the facilities is provided through a common switchyard, then the combined maximum authorized real power rating of the facilities will be used to determine the applicability of a reliability standard for each of the facilities.

ONTARIO

> **From 2013 to 2017, the IESO issued a number of RFPs targeted at procuring energy storage capacity. The RFPs were designed to promote early-stage, proof of concept energy storage technologies.**

In 2018, the IESO created the Energy Storage Advisory Group ("**ESAG**"). ESAG's work culminated in a report issued in December 2018 entitled "*Removing Obstacles for Storage Resources in Ontario*". The report indicated that one of the largest regulatory obstacles to the integration of energy storage facilities in the IESO-administered markets is the minimum MW threshold to connect energy storage resources at the wholesale level (1 MW). Further ambiguities regarding registration and authorization requirements were also identified.

In Fall 2019, the IESO initiated the Storage Design Project ("**SDP**"). One of the mandates of the SDP was to identify and refine a matrix of interim and long-term design issues for the integration of energy storage resources at the wholesale level. As such, the SDP's work was limited to energy storage facilities registered to participate in the IESO's administered markets and excluded storage resources not within the jurisdiction of the IESO market rules such as behind-the-meter facilities.

In February 2020, the SDP released an interim design document putting forward temporary measures for addressing energy storage participation barriers in the IESO-administered markets. A long-term design document was subsequently released on September 15, 2020. The latter design document recommended certain IESO market rule and market manual amendments to effect the proposed temporary measures, including regulatory requirements for energy storage resources at every stage of IESO market participation from registration to operations.

Those IESO market rule and manual amendments were brought to the IESO's Technical Panel in October 2020, where they were approved for recommendation to the IESO Board of Directors. The market rule and manual amendments were then approved at the December 2020 IESO Board meeting and are effective as of January 18, 2021.

The September 2020 long-term design document was intended to provide only a high-level roadmap for how the IESO will treat storage in the IESO-administered markets going forward, once IESO tool upgrades are made to fully integrate storage resources following the implementation of the IESO's Market Renewal Program ("**MRP**"). Further market rule and market manual amendments, which will be required to permanently integrate energy storage participation in the IESO-administered markets, are not expected to be developed and implemented until after the implementation of the MRP.

It is anticipated that bringing distributed energy resources ("**DERs**") and behind-the-meter resources into the IESO-administered markets will be addressed through other avenues such as the IESO's Market Development Advisory Group, the IESO's Innovation and Sector Evolution White Paper Series, and possibly the Ontario Energy Board's ("**OEB**") stakeholder consultation on DERs. Some coordination between the IESO and the OEB will therefore be imperative to the successful integration of energy storage resources into Ontario's electricity markets. For example, the long-term design document

suggests that the OEB and Government should consider any necessary revisions to new settlement amounts or uplift charges needed to implement energy storage participation in the IESO's administered markets.

How the long-term vision for the integration of energy storage resources fits into the IESO's future procurement policies, as contemplated in the IESO's recently released three-part approach towards procuring resource adequacy, also remains to be seen.

Furthermore, it remains to be seen if and to what extent the recent hiatus of the Industrial Conservation Program (ICI) in Ontario will have on the development of behind-the-meter energy storage resources by Class A participants given that most of such project development to date has been for the purpose of decreasing Global Adjustment payments.

QUÉBEC

In December 2020, Hydro-Québec announced that it has launched a subsidiary named EVLO Energy Storage Inc. ("**EVLO**") which designs, sells and operates sustainable energy storage systems. EVLO has developed lithium iron phosphate batteries that are used in energy storage systems intended for power producers, transmission providers, distributors and commercial and industrial users in relation to medium and large scale energy storage. EVLO has also developed power control and energy management software.

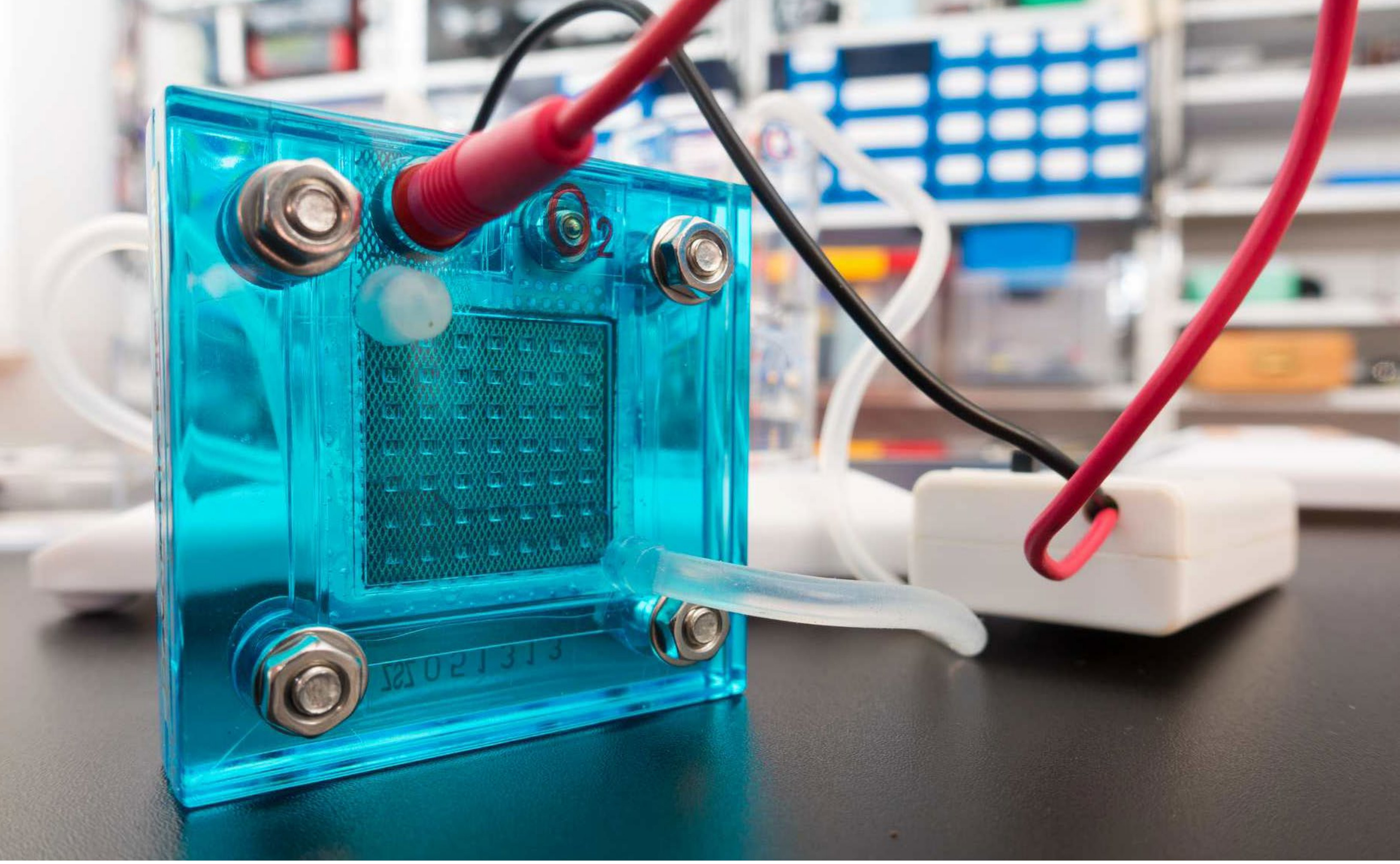
Some Hydro-Québec projects have already incorporated the technology that EVLO offers, including:

- the Quaqtaq off-grid system pilot project on renewables and energy storage in Northern Québec, which includes rooftop solar panels;
- Québec's first microgrid project located in Lac-Mégantic which includes solar panels, energy storage units and energy efficiency tools, and which can operate independently from Hydro-Québec's main grid; and
- Hydro-Québec's photovoltaic solar generating station connected to the grid with an installed capacity of 8 MW in La Prairie.

EVLO also has signed a memorandum of understanding with Innergex in order to provide the lithium iron phosphate battery that will be used as part of Innergex's Tonnerre project located in Bourgogne-Franche-Comté, France, which involves the installation of a 9 MW storage system in the transmission system operated by France's national transmission provider Réseau de Transport d'Électricité ("**RTE**") under a long-term agreement between RTE and Innergex.

BRITISH COLUMBIA

While the Province's electricity infrastructure has been predicated on the significant storage capacity of BC Hydro's legacy hydroeletric facilities, the Province may soon look to alternative sources of storage capacity. As part of its Clean Power 2040 consultations, BC Hydro will consider the potential for utility-scale batteries and pumped storage to provide additional capacity as the utility plans for the 2030-2040 time horizon. British Columbia is already home to three operating electrochemical energy storage projects, as well as a significant planned pump hydro storage project. According to one recent study, based on current rate structures, the use of electricity storage systems for behind-the-meter applications would start to be profitable in British Columbia from 2025 onwards.



Unlocking the Potential of Hydrogen: What lies ahead for Canada?

Authors: Stephen Furlan, Jamie Gibb, Will Horne, Kerri Lui, Dave Nikolejsin and John Osler

Overview

Hydrogen is a potentially transformative source of low or zero-carbon energy that can be incorporated into numerous upstream, midstream, and downstream applications throughout our energy system. While serious industrial application of hydrogen has been contemplated since the 1970s, this uniquely versatile resource has in recent years received much more interest as various jurisdictions devise new energy strategies in the pursuit of a greener economy.

Canada and 72 other countries have committed to achieving net-zero greenhouse gas ("**GHG**") emissions by 2050. Many argue that net-zero is virtually impossible without hydrogen. It has been projected that hydrogen will supply approximately 27% of Canada's energy demand by 2050. Since half of Canada's GHG emissions are associated with the end-use combustion of fuels like gasoline, diesel, natural gas and kerosene (jet fuel), achieving the net-zero target will likely require a transition to energy carriers that produce low or zero GHG emissions at end use.

Already, 18 economies comprising more than 75% of global GDP are developing and rolling out hydrogen strategies. Several countries, including Germany and South Korea, have dedicated substantial funds to national hydrogen strategies. On June 3, 2020, Germany released a stimulus package of €9 billion (C$13.7 billion) for the ramp-up of hydrogen technologies. In Canada, governments are just starting to turn their attention to this sector with a series of recently published strategies, and the industry itself is in its nascent stages.

THE THREE COLOURS OF HYDROGEN

Hydrogen can be sourced from techniques that can be broadly categorized by three colours.

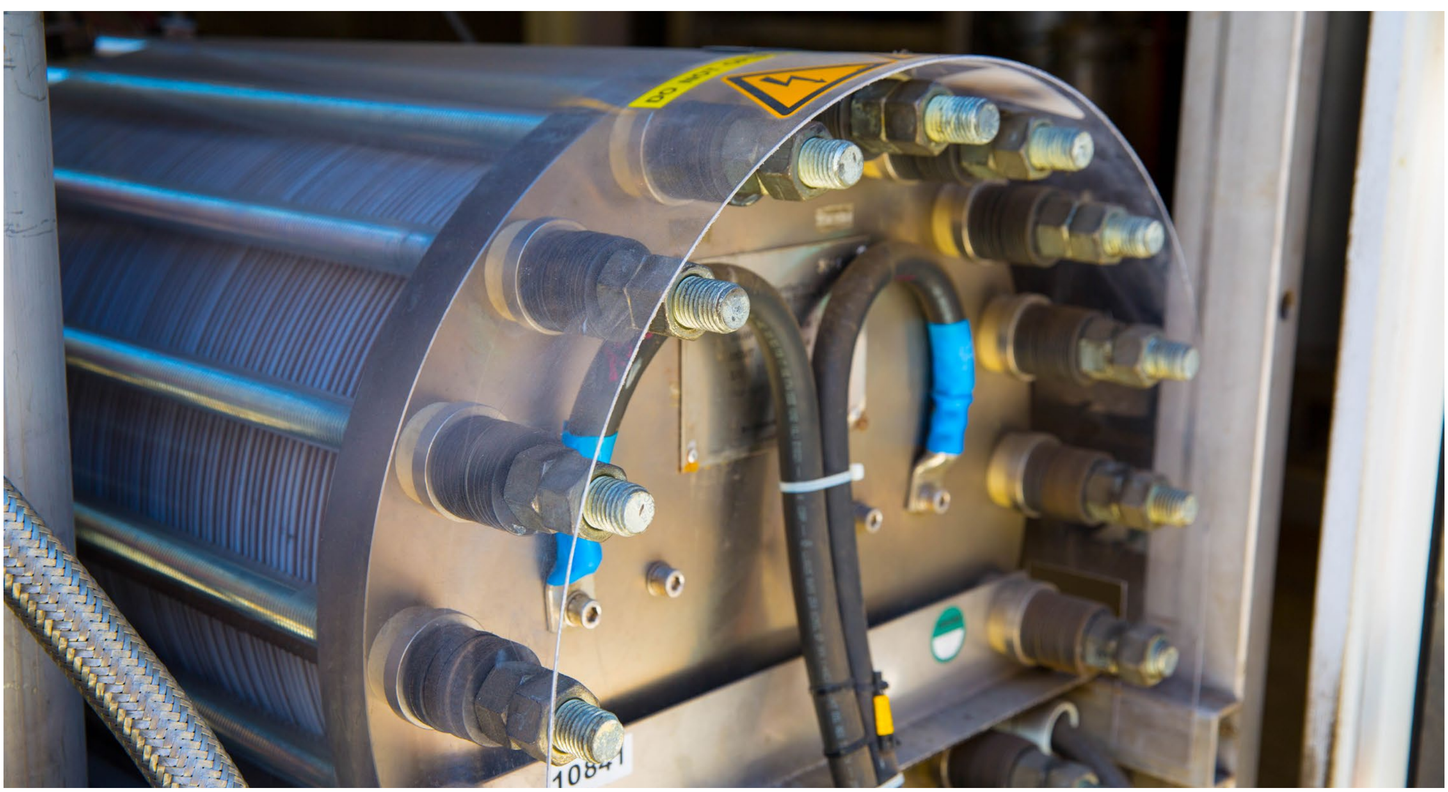
Grey hydrogen is derived from fossil fuels (primarily natural gas); it is currently the main method of production, and most of the produced hydrogen is consumed at the same location (e.g. at an oil refinery or gas processing facility).

Blue hydrogen is also derived from fossil fuels, but includes any number of carbon capture, storage and sequestration ("CCUS") technologies to reduce carbon emissions by up to 90%.

Green hydrogen is derived from water using electrolysis, an electricity-powered process that breaks down water into its constituent hydrogen and oxygen molecules. The electricity used must be from renewable (e.g. wind or solar) or nuclear sources in order to be considered truly green.

Accordingly, not all hydrogen is created equal with respect to climate benefits. Blue and green hydrogen are commonly referred to as "clean" hydrogen. Green hydrogen does not produce any carbon emissions and is therefore considered to be the cleanest. However, as detailed below, the current cost of producing green hydrogen is significantly higher than the cost of producing blue hydrogen.

Canada is fortunate to be among the world's lowest cost producers of low or zero-carbon hydrogen. According to a report from Alberta's Transition Accelerator, provinces with ample low-carbon electricity (e.g. from hydropower, nuclear or renewables), electrolysis can produce 'green' hydrogen for $2.50 to $5.00/kg H_2 ($18 to $35/$GJ_{hhv}$ H_2). In provinces with low-cost natural gas and the geology suitable for permanently sequestering the byproduct CO2, 'blue' hydrogen can be produced at a price of $1.50 to $2.0/kg H_2 ($10 to $14/$GJ_{hhv}$ H_2). It is anticipated that by 2030, green hydrogen will be cost-competitive as a result of declining costs of renewables and the scaling up of electrolyzer technology.



What Markets are Being Targeted?

Numerous end-use markets for hydrogen have been identified and are on the rise, including transportation, industrial heating and feedstock, and heating for buildings. One of the key advantages of hydrogen is its potential to penetrate traditionally difficult-to-decarbonize market segments, including heavy trucking, aviation, and chemical and steel production.

TRANSPORTATION

The federal government has set targets for zero-emission vehicles to make up 30% of sales of light-duty vehicles by 2030 and 100% by 2040. Zero-emission vehicles include battery electric vehicles, fuel cell electric vehicles, and plug-in hybrids.

Fuel cell electric vehicles can use hydrogen directly as a fuel and British Columbia and Québec have already begun deploying hydrogen fueling infrastructure to support its use. Public transit around the world has begun the shift to fuel cell electric buses, with over 2,000 in operation globally, half of which are powered by Canadian technology.

Fuel cells are also projected to play a vital role in ships, rail, and heavy-duty and medium-duty trucks. The high energy density and fast filling capabilities of fuel cells remove the need for several large batteries and reduce refuelling times. British Columbia-based Ballard Power Systems has been leading hydrogen fuel cell development for over 40 years.

INDUSTRIAL & COMMERCIAL HEATING

Hydrogen can be used for industrial applications where high heat is needed (e.g. metals and chemical production), and hydrogen is garnering attention as a low-carbon heating option for buildings by blending it with natural gas or as a stand-alone alternative.

> **A number of operations internationally and domestically are running pilot projects to determine the feasibility of blending hydrogen with natural gas systems. This is especially important where governments have introduced regulations to lower the carbon intensity of fuels.**

As a result, there is real potential for hydrogen to become a major part of the heating fuel mix in Canada, which would require investment in hydrogen pipelines. This could be accomplished through a combination of retrofits to petroleum pipelines and new builds. Enbridge Gas Inc. and Cummins Inc. have recently partnered to develop a project in Markham, Ontario, that will blend renewable hydrogen gas into existing natural gas networks. The hydrogen-blending pilot project is the first of its kind in North America.

REFINING CRUDE OIL

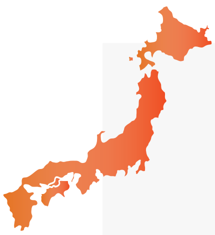
Currently, the largest use of hydrogen around the world is in the refinement of crude oil and the creation of petrochemicals. The majority of hydrogen used in these processes is grey hydrogen that is produced on-site either as a by-product or from dedicated facilities. Using blue or green hydrogen can reduce the carbon intensity of the refining and petrochemical industries. This can be achieved by switching to new green or blue supply sources or by incorporation of CCUS technology into existing facilities.

CCUS technology is rapidly evolving in Canada and internationally and its deployment represents another large opportunity linked with hydrogen development. Alberta's oil and gas sector is a global leader in CCUS with its existing technologies and infrastructure. Two new CCUS projects have recently been developed in Alberta:

Shell Canada Energy's Quest CCUS facility and the Alberta Carbon Trunk Line Project, placing Alberta at the forefront of the development and deployment of this technology.

EXPORTS

There is a growing overseas market for hydrogen as countries roll out their hydrogen strategies. With worldwide demand for hydrogen increasing, the global market is expected to reach more than C$2.5 trillion by 2050. For example, in the past year:



Japan announced it aims to establish commercial supply chains that will procure 300 kt H_2/yr (822 t H_2/day) by 2030;

South Korea has projected a national demand of 5.26 Mt H_2/yr (14.4 kt H_2/day) by 2040; and

Germany recently announced a national demand for about 2.5 Mt H_2/yr (7.0 kt H_2/day) by 2030.

Industry Challenges - Midstream

The future of hydrogen is not without its challenges. These include the need to make hydrogen cost-competitive with other energy sources so as to attract the massive scale of investment required to produce the desired outcomes, both in terms of GHG reduction and economic benefit.

Blue hydrogen typically requires long distance transmission capacity, given that feedstock is typically located farther away from population centres where it is consumed. While hydrogen can be blended into existing natural gas networks, there is a maximum threshold concentration. A large-scale industry will likely require transmission capacity in the form of new pipelines or the retrofit of existing pipelines. Alternatively, existing natural gas infrastructure could be used to ship natural gas for processing into blue hydrogen elsewhere.

Green hydrogen, which may be deployed on a smaller scale and on localized networks, may be able to rely on truck and tank-based infrastructure, but this too requires the retrofitting of existing systems or the building of new ones to withstand the pressures and temperatures.

A global trading supply chain will also have to account for the advantages and disadvantages of transporting hydrogen in one of three forms (liquid ammonia, liquid organic hydrogen carriers, or proprietary solutions), and there is currently no consensus as to a preferred medium or any significant progress at harmonization between potential supply and demand centres.

Overcoming these challenges will require a coordinated effort by the federal government and provincial governments, as well as internationally. The global LNG industry was able to evolve and grow due to a standardized product and standardized means of transportation and handling.

Government Policies

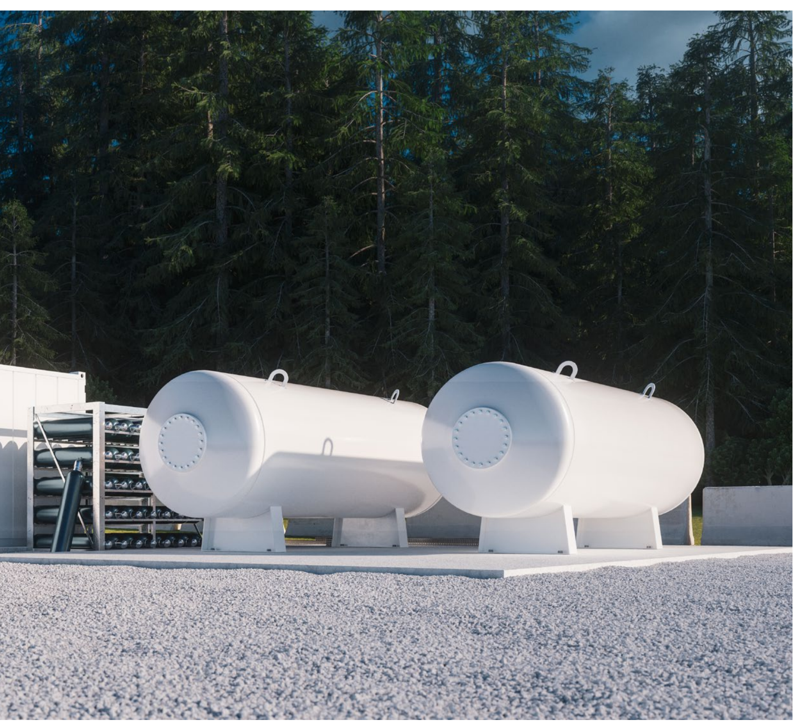
FEDERAL STRATEGY OVERVIEW

On December 16, 2020, the federal government released its long-awaited *Hydrogen Strategy for Canada* (the "**Strategy**"). The Strategy was presented shortly after the tabling of the *Canadian Net-Zero Emissions Accountability Act* and the federal government's pledge to achieve net-zero emissions by the year 2050.

The Strategy claims that if Canada can properly leverage its competitive advantages in hydrogen production, the country can create more than 350,000 jobs in the sector by 2050 and generate revenues of $50 billion per year. The announcement did not include any new funding over and above the previously released $1.5 billion investment fund for low-carbon fuels announced in early December 2020. The Strategy does reference tax credits and subsidies as potential government-led measures; however, no details were announced with the Strategy. The Strategy targets private sector investment as a major driver of the necessary growth.

At least for the near term and in order to exploit incumbent competitive advantages, the federal government has singled out Canada's vast natural gas reserves, primarily in Alberta, as a main fuel source for blue hydrogen production. The Strategy also acknowledges that Canada has outstanding renewable resources (including existing hydroelectric generation in B.C., Quebec, Manitoba, and Newfoundland) that can be used to generate green hydrogen, and can do so in a distributed (i.e. decentralized) manner.

In this way, the Strategy recognizes the relative strengths of Canada's different regions. For instance, Ontario's nuclear industry has the potential to work synergistically with hydrogen by using off-peak electricity for electrolysis or by using excess steam from nuclear reactors (including the small modular reactors ("**SMRs**") of the future) to improve electrolyzer efficiency. Alberta has a clear advantage in blue hydrogen production owing to its enormous natural gas reserves and well-established industry expertise and infrastructure. Industrial and natural resource variation could well prove to be a key advantage for Canada, allowing the country to hedge its bets, compared to competitors that may be more limited in resource types and overall production scope.



Layout of the Federal Hydrogen Strategy

The government's plan is broken down into three distinct phases: the near term (next five years), the mid-term (2025-2030), and the long-term (2030-2050). Featuring 32 recommendations across eight pillars, the Strategy has no shortage of ideas for how to transform the Canadian hydrogen industry.

The eight pillars of the Strategy are:

1. **Strategic Partnerships**
2. **De-Risking Investments**
3. **Innovation**
4. **Codes and Standards**
5. **Enabling Policies and Regulation**
6. **Awareness**
7. **Regional Blueprints**
8. **International Markets**

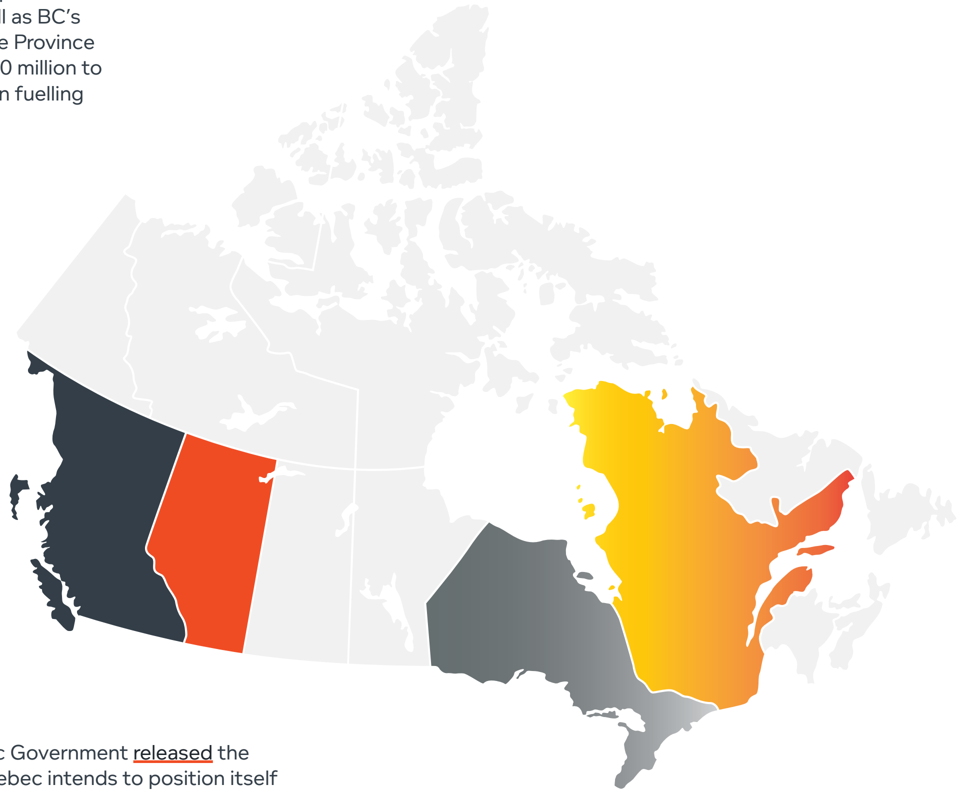
The Strategy's near term plan focuses on providing a solid foundation for developing the Canadian hydrogen economy by planning supply and distribution infrastructure and the introduction of new policy and regulations. After stimulating growth in the near-term, the mid-term will focus on hydrogen utilization in the applications that provide the best value proposition, while technology matures and more end-use applications near commercial readiness. Finally, the long-term will focus on the exploitation of the Canadian hydrogen economy as scale increases and commercial applications continue to develop.

Overall, the federal hydrogen strategy does not promote an industrial policy which favours one technology over another, but rather remains focused on achieving Canada's emission reduction targets. With the recent announcement of the Clean Fuel Standard and the federal carbon pricing the technology that will succeed with be determined on its ability to produce net-zero energy.

CANADIAN LANDSCAPE

The following Canadian provinces have released or indicated they intend to release a provincial hydrogen strategy:

- **British Columbia** – Hydrogen is a named component in the Clean BC Strategy released in 2018 as well as BC's 2019 Hydrogen Study. In September 2020, the Province partnered with Hydrogen BC and allocated $10 million to the construction and operation of 10 hydrogen fuelling stations in the Province.
- **Alberta** – Hydrogen strategy is part of a new flagship Natural Gas Vision and Strategy that was unveiled in October 2020. The strategy is focused on CCUS allowing for the use of existing technologies and infrastructure to produce blue hydrogen through sequestration of the resulting carbon in generating hydrogen from natural gas.
- **Ontario** – The Government of Ontario released a discussion paper for public consultation in November 2020. A provincial strategy is anticipated to be released in Q2 2021. The discussion paper emphasizes producing green hydrogen through electrolysis, using hydrogen for electricity storage and blending hydrogen with natural gas to make Ontario's gas system cleaner.



- **Quebec** - On November 16, 2020, the Quebec Government released the 2030 Plan for a Green Economy Summary. Quebec intends to position itself as a leader in the production of green hydrogen and bioenergy. The formal green hydrogen and bioenergy strategy is anticipated to be released in 2021.

Conclusion

As governments around the world shift toward low-carbon fuels, it is clear that hydrogen will feature prominently in the coming decades. Hydrogen forms a necessary part of a broader constellation of solutions to the global decarbonization challenge. However, there are many challenges to get there. The industry remains in its infancy, with several unresolved issues such as transportation, storage and cost of production.

Nevertheless, numerous forces are coalescing to make hydrogen a viable player in the Canadian energy economy, including the ongoing implementation of carbon pricing, large-scale strategic planning, and the beginnings of required infrastructure improvements. As a result, hydrogen will have a vital role to play in achieving the dual goals of decarbonization and revitalizing Canada's energy industry.

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Our Power Group consists of more than 40 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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