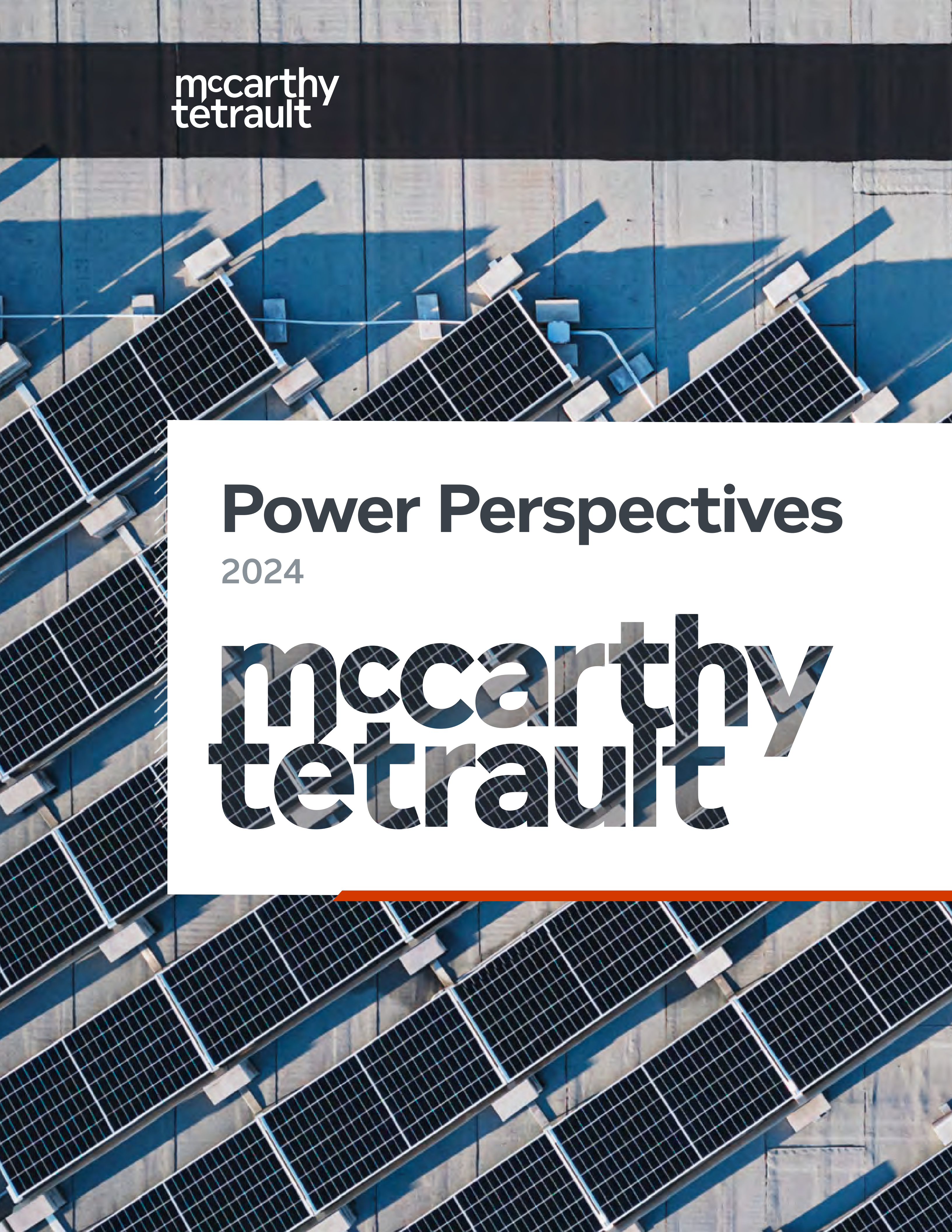

Power Perspectives

2024

McCarthy Tétrault

The National Energy Group of McCarthy Tétrault LLP is pleased to present: *Power Perspectives 2024*.

Message from our Co-Editors-In-Chief, Kerri Howard and Jacob Stone:
This publication is our ninth 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, and associated emerging energy sectors, in 2023. It has been a transformational year in the power sector, with continued focus on the energy transition amid a backdrop of numerous regulatory developments. In this publication we will provide updates on Aboriginal law, federal and provincial environmental and other regulatory changes, the notable increase in the procurement of renewable energy in several provinces, updates in certain emerging sectors, including carbon capture, storage and utilization and small modular reactors, and provide a discussion around the expanded tax incentives fuelling the energy transition. We have also highlighted key trends to watch for in 2024. We hope that you will find this publication to be both interesting and informative.

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British Columbia Regional Overview

INTRODUCTION

There was a seismic shift in British Columbia's energy sector in 2023 as BC Hydro, the province's electric utility, reconsidered the future energy needs of the province to meet both natural load growth and the government's environmental policy goals and concluded that the province will require much more power, and much sooner, than contemplated under previous forecasts. As BC Hydro, independent power producers (IPPs), Indigenous groups and other stakeholders gear up for a power call in 2024, the past year also witnessed other developments in the energy sector. These included the renewal of existing electricity purchase agreements (EPAs), the looming completion of B.C.'s Site C hydroelectric project, adjustments to the province's CleanBC climate initiative, and key developments affecting the future of B.C.'s nascent LNG industry.

BC HYDRO'S CALL FOR POWER

On June 15, 2023, the B.C. government **announced** that BC Hydro and Power Authority (BC Hydro) would be launching a **new call** (Power Call) for sources of renewable, emission-free electricity. The Power Call will be BC Hydro's first call for power since its **Clean Power Call** of 2008.

The Power Call, expected to launch in the spring of 2024, will seek to acquire new sources of power as early as 2028. The program will focus on projects that offer 100% clean, renewable energy, including wind and solar, and is expected to prioritize large, utility-scale projects. The Power Call will also include C$140 million for the B.C. Indigenous Clean Energy Initiative to support Indigenous-led projects, some of which may not otherwise be competitive owing to their smaller size.

Precursor to the Power Call: IRP Update Revises Forecast

On the same day it announced the Power Call, BC Hydro filed its first **"signpost" update** (Signpost Update) to the 2021 Integrated Resource Plan (2021 IRP) with the British Columbia Utilities Commission (BCUC), which was followed by an **update to the 2021 IRP** (IRP Update and, together with the Signpost Update, the 2023 Updates). The Signpost Update, among other things, confirmed the need for new sources of power in B.C. sooner than had been anticipated in the 2021 IRP. The 2023 Updates were previewed in a letter sent by BC Hydro to the BCUC on March 23, 2023, anticipating the need to renew EPAs expiring after 2026, acquire new greenfield energy resources and advance capacity resources, such as transmission projects and utility-scale batteries.

The 2023 Updates and their commitment to procuring new power in the short and medium term mark a shift in policy from BC Hydro, which had previously maintained that B.C. would be in a position of surplus energy beyond the end of the decade. BC Hydro's energy forecasts from 2021 anticipated an energy surplus of 500 GWh by 2030, which has now been revised in the 2023 Updates to an energy deficit of 3,500 GWh by 2030. In the 2023 Updates, BC Hydro explained this 4,000 GWh swing in the forecast by referencing the following three factors:

- **Increased load of 2,300 GWh**: This is largely attributable to an increase from commercial and large industrial customers. BC Hydro broke down the forecast by sector, and while forestry was relatively unchanged, anticipated load for mining and oil and gas (including LNG) increased. Demand from the oil and gas sector was softer in the short term due to delayed in-service dates of some projects but increased significantly in the long term closer to 2030. Such increased demand from commercial and large industrial customers is consistent with the goals of the CleanBC plan, B.C.'s signature electrification and decarbonization strategy.
- **Decreased supply of 900 GWh**: This is attributed largely to a decrease in expected generation from biomass facilities related to fuel-supply constraints and future fuel-supply risks. In the 2021 forecasts, biomass generation had been considered to be a significant contributor to the generation capacity of BC Hydro's portfolio.
- **Achievement of demand-side savings of 800 GWh:** These savings were achieved in 2021 and 2022 and are now integrated into historical data and can no longer be relied upon as a new resource for future years. BC Hydro had previously maintained that energy saved through demand-side measures would be a critical component of the surplus projected in the 2021 IRP.

The Power Call

In the 2023 Updates, BC Hydro acknowledged that the failure of the 2021 IRP to allow for the earlier acquisition of new energy resources as needed was a weakness. To address the rapid pace of change of B.C.'s energy transition, BC Hydro now proposes to adopt a new "living" long-term resource-planning cycle with regular BCUC filings that will be better able to address the dynamic nature of the energy system as it evolves. Such filings, expected approximately every 18 months following the BCUC's decision on the IRP Update, would not be comprehensive but would target specific resources, inputs, options, and forecasts on a rolling basis. This new model of resource planning is expected to afford BC Hydro flexibility in its ability to match supply with demand in real time and adapt to the realities of a bigger and more diversified power grid.

The above factors, all driven by global, national, provincial and local factors, have attuned BC Hydro to the need for more power in the short and medium terms. The 2023 Updates disclose a number of action items to address the projected shortfall of 4,000 GWh, which include:

- **Acquisition of 700 GWh from existing generation resources:** This presumably reflects currently underutilized generation capacity or EPAs that may not have been renewed under the 2021 IRP. This capacity is expected to be brought online prior to 2029.
- **Acquisition of 3,000 GWh of power from new greenfield sources:** With commercial operation dates as early as fall 2028, this new supply will be achieved through the Power Call.

Almost immediately after announcing the Power Call, BC Hydro kicked off an extensive **engagement and consultation process** consisting of information sessions, workshops on the design and key elements of the Power Call, technical sessions and consultations with IPPs and **First Nations**. This process is expected to run through January 2024.

While the engagement and consultation process remains ongoing at the time of writing and is expected to continue to shape key elements of the Power Call, some features or potential features of the Power Call have been previewed by BC Hydro in workshops, presentations, **a draft EPA term sheet** (Draft EPA Term Sheet), a draft general request for proposal terms summary (Draft RFP Terms) and a draft **Request for Proposals** (Draft RFP):

— To participate in the Power Call, projects must be new, greenfield projects located in B.C. (excluding Fort Nelson and certain areas not integrated with BC Hydro) and they must connect or deliver to BC Hydro's integrated system without passing through another jurisdiction. Expansions to existing facilities that consist of new generating units are also eligible.

— BC Hydro is looking for "clean" or "renewable" energy projects, within the meaning of B.C.'s ***Clean Energy Act*** (CEA), which includes biomass, biogas, geothermal heat, hydro, solar, ocean, wind and any other prescribed resource (which currently includes biogenic waste, waste heat and waste hydrogen). BC Hydro is not expecting to set resource-specific targets, but wind projects are anticipated to be well positioned competitively to meet the Power Call criteria.

— With a minimum eligible project size of 40MW, BC Hydro is generally looking for larger clean or renewable energy projects for economies of scale, projects that are cost-effective and feature high reliability in energy delivery, and projects that will connect to the existing transmission system and require modest or no system upgrades to the BC Hydro system. Projects not directly connecting to the BC Hydro system are responsible for making their own arrangements to deliver their energy to the system.

— The interconnections process will follow a similar process as past competitive calls, following the competitive electricity acquisition process set out in the open access transmission tariff.

— First Nations partnership opportunities are focal, and models for minimum economic participation by First Nations are being elaborated (discussed further below).

The Draft RFP contemplates issuance of the final RFP on April 2, 2024, with a submission deadline of September 16, 2024, and award announcements December 16, 2024. EPAs so awarded will be for projects with commercial operation dates ranging from October 1, 2028, to October 1, 2031.

The Draft RFP Terms and Draft RFP indicate that proponents will need to pay a registration fee of C$5,000 and a proposal submission fee of C$13,000 per proposed project and will be required to provide bid security of C$25,000/MW of plant capacity in the form of a letter of credit. An executed feasibility interconnection study agreement must also be submitted to BC Hydro's interconnections department together with any required study deposit, and interconnection requests will be required to be submitted by May 8, 2024, as a precursor to a proposal. Network upgrade costs to be incurred by BC Hydro to connect a proposed project will be factored into the evaluation by adjusting the bid price.

The Draft RFP indicates that eligibility requirements will include, among other things, a minimum First Nations equity requirement (discussed further below), and an evaluation that will include a First Nations consultation adequacy assessment, a risk assessment, a commercial and quantitative evaluation, including First Nations economic participation evaluation and considerations beyond individual bid adjustments. A First Nations benefit adjuster (FNBA) is anticipated to apply in the evaluation of proposals, whereby the adjusted bid price would be reduced according to the FNBA, which will consist of two components: credit for First Nations equity ownership above the minimum requirement (which will be credited C$0.125/MWh for each additional percentage point between 26% and 49%, an additional C$0.40/MWh for projects with 50% Indigenous ownership and an additional C$0.60/MWh for projects with 51% Indigenous ownership, up to a maximum of C$4/MWh for 51% Indigenous ownership), and credit of C$1/MWh if a proposal is supported by a letter from one or more First Nations in whose territory the project is located and who are not equity owners of the proposed project, confirming that additional economic benefits other than equity ownership have been, or are to be, received.

The Draft RFP also indicates that BC Hydro may consider providing a capacity credit in the proposal evaluation for energy resources that can provide capacity when needed, such as cold winter evenings when demand is high. The capacity credit would not be available to wind, solar or run-of-river projects but may be considered for biomass, geothermal and storage hydro.

In light of the costs to BC Hydro of resource integration for more variable intermittent energy sources, the Draft RFP indicates that a resource integration cost of C$2/MWh will be applied to wind and solar resources, but not other resource types.

All of the terms in the Draft RFP are preliminary and subject to change as BC Hydro's consultation continues.

Demand-Side Measure

Concurrent with the Power Call, BC Hydro also pursued **a redesign of its residential electricity rates** to offer residential customers an optional time-of-day pricing model (TOU Model). The TOU model was **approved by the BCUC** on December 12, 2023. Under the TOU Model, which applies to every day of the year, residential customers will be billed for total electricity used according to the existing two-tiered rate but will receive a discount of $0.05/kWh for electricity consumed overnight (11 p.m. to 7 a.m.) and will be charged a surcharge of $0.05/kWh for electricity consumed during peak hours (4 p.m. to 9 p.m.). No discount or surcharge will be applied during off-peak hours (7 a.m. to 4 p.m. and 9 p.m. to 11 p.m.). Such demand-side measure, expected to cause some high-consumption activities (such as electrical vehicle charging) to shift to low-load times of day, will help spread the aggregate residential load more evenly over the province's generation, transmission and distribution infrastructure at any given point in time. This will likely ease capacity constraints on the provincial grid, allowing for greater efficiency and supporting the further development of the provincial electricity system.

Draft Electricity Purchase Agreement

The Draft EPA Term Sheet was released in November 2023 and elaborated in the **2024 Call for Power Consideration Memo** (Consideration Memo) subsequently published by BC Hydro following consultation. BC Hydro further released a **specimen EPA** (the Specimen EPA) for new projects under the Power Call on January 8, 2024, which incorporates the Draft EPA Term Sheet (as further iterated in the Consideration Memo) and outlines the proposed EPA terms for the Power Call. We continue to review the Specimen EPA following its recent release, but are able to draw some general conclusions. While its terms are preliminary and subject to comment and consultation, the Specimen EPA terms are generally consistent with past power calls and the Specimen Renewal EPA (defined further below) for recent EPA renewals (discussed further below), with a few notable differences:

- **EPA Term**: The Specimen EPA contemplates an EPA term of 30 years, which may be extended for up to 364 days for reasons related to force majeure. Sellers will be required to make commercially reasonable efforts to operate their plants to generate clean or renewable electricity in the event that clean or renewable resource requirements change during that term.
- **Liquidated Damages/Guaranteed COD Extension:** The Draft EPA Term Sheet originally indicated that proponents would be liable for liquidated damages for failure to meet interim agreed project milestones (completion of permitting, completion of procurement and construction commencement), which would have been reimbursable without interest if the guaranteed commercial operation date (COD) was met. However, as BC Hydro stated in the Consideration Memo, the Specimen EPA does not contain milestone liquidated damages other than liquidated damages payable if the seller does not achieve their guaranteed COD (with allowance for up to 180 force majeure days). The maximum extension of a guaranteed COD will be two years.

— **No Firm Energy Commitment**: The Specimen EPA does not contemplate a firm energy commitment or penalties for non-delivery except where an optional capacity commitment applies, in which case liquidated damages will be payable for shortfalls. BC Hydro will purchase and accept energy delivered at the point of interconnection, with no obligation to accept or pay for delivered energy in excess of hourly limits.

— **Energy Pricing**: The Specimen EPA indicates that the hourly energy price will be multiplied by a time of delivery factor (TDF) that is a percentage for each on-peak and off-peak hour in each month of the year. Notably, the TDF percentages set out in the Specimen EPA differ, in some cases significantly, from the TDF percentages in recent EPAs Renewals, with TDFs for off-peak hours and on-peak hours of 19% and 45%, respectively, in May and June, compared with 50% and 38%, respectively, for May, and 67% and 79%, respectively, for June, in the recent EPA renewals. The hourly energy price will be escalated each year based on the B.C. consumer price index (CPI) until COD, and thereafter at 30% of B.C. CPI (compared with 50% in past EPAs).

Termination Payments: The Specimen EPA contemplates various EPA termination payments. Upon termination by the seller for failure to obtain material permits, the seller is liable for a termination fee of C$60,000/MW multiplied by the plant capacity. Upon termination by BC Hydro other than for force majeure, an Aboriginal claim (defined as a legal claim or threat of legal claim alleging potential impacts that breach any First Nation's rights under s. 35 of the *Constitution Act, 1982*) or a failure to obtain material approval from the BCUC in time, the seller is liable to pay BC Hydro a termination payment equal to any loss suffered by BC Hydro, which will be determined by comparing the value of the remaining EPA term, estimated contract quantities based on the energy estimate during the term from the seller's proposal and the price payable under the EPA had it not been terminated to the relevant market prices for equivalent quantities for the remaining EPA term, with adjustments for differences between the product subject to the market price and the product specified under the RFP eligibility requirements and the EPA. This payment is not subject to a cap, and additional liability may apply in a case of deliberate breach. On termination by a seller for material default by BC Hydro prior to COD, BC Hydro is liable for a payment equal to the seller's project development costs to date plus 15%, less the net realizable value of the project assets; post-COD, the termination payment is based on the loss, if any, suffered by the seller, determined similarly to the foregoing seller termination payment, but taking into account the actual amount and rate of generation of the project since COD.

The Specimen EPA contemplates that each EPA will be required to be filed with and approved by the BCUC, though it is possible that, similarly to prior BC Hydro procurements, the B.C. government could exempt the EPAs from this process to relieve the burden on the BCUC.

All of the terms in the Specimen EPA are preliminary and subject to change, with the current comment period ending on January 22, 2024.

Involvement of Indigenous Peoples

DRIPA

The Power Call is BC Hydro's first call for power since the provincial government enacted the ***Declaration on the Rights of Indigenous Peoples Act*** (DRIPA), which affirms the application of the **United Nations Declaration on the Rights of Indigenous Peoples** (UNDRIP) to the laws of B.C. and forms the impetus for the implementation of UNDRIP in the province. The provincial government is **required under DRIPA** to ensure that the laws of B.C. are consistent with UNDRIP, and to prepare and implement an **action plan** to achieve the objectives of UNDRIP. Under the current DRIPA action plan, the provincial government has identified goals and proposed actions related to Indigenous natural resource governance, economic development, environmental stewardship, and political autonomy, among others. DRIPA, as the **first UNDRIP-affirming legislation enacted in North America**, is driving an unprecedented transformation of Indigenous–state relations in the province. The enactment of DRIPA places B.C. at the forefront of Indigenous–settler reconciliation globally.

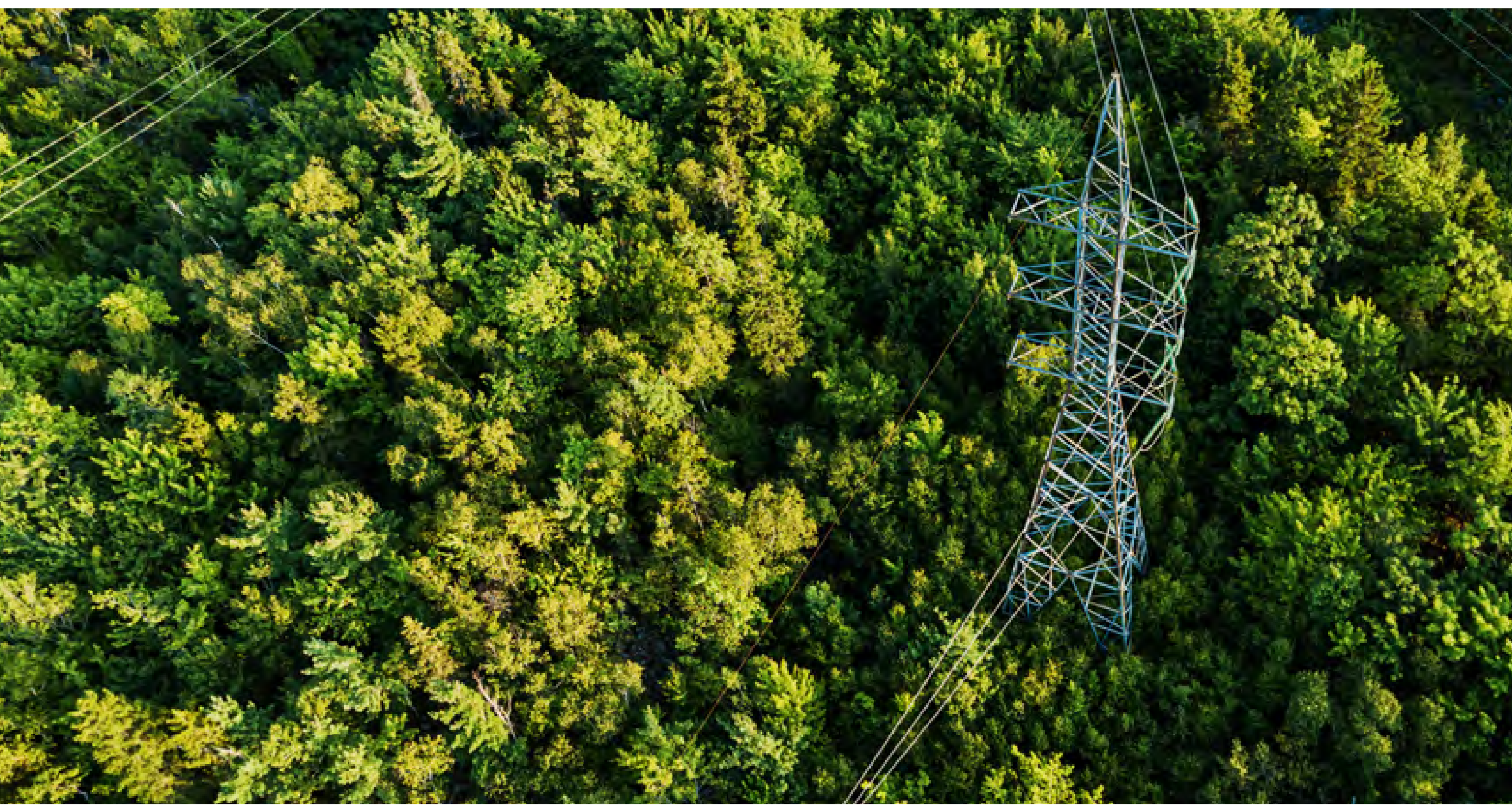
DRIPA sits atop the pre-existing policy framework surrounding Indigenous participation in B.C.'s clean energy sector. One of the objectives of the *CEA*, which forms part of BC Hydro's mandate, is to foster the development of Indigenous communities through the use and development of clean or renewable energy. The BCUC has also confirmed that, although it cannot act beyond the scope of its legislated mandate, it nonetheless considers all applicable government policy and legislative directives, including DRIPA and the province's principles for Indigenous reconciliation, in carrying out its mandate.

Being both a market maker and an agent of the Crown, BC Hydro offers the B.C. government a unique vehicle with which to advance Indigenous reconciliation in furtherance of the goals of CEA and DRIPA and in service of the actions identified in the DRIPA action plan.

First Nations Economic Participation

The Power Call will involve more Indigenous project ownership and development than any of its predecessors. BC Hydro is designing the Power Call process in consultation with Indigenous groups and has established a new task force to provide strategic advice by, among other things, focusing on Indigenous ownership opportunities and consulting Indigenous experts. Under the **November 2023 draft** of the proposed First Nations economic participation model that BC Hydro is developing in ongoing consultation with Indigenous groups and stakeholders, as further iterated in the Consideration Memo and the Draft RFP, the following criteria is proposed to be used to assess projects participating in the Power Call:

— **Eligibility Requirement:** To qualify for the Power Call, proposed projects must include a minimum of 25% Indigenous equity ownership in the entity owning and



controlling the generating assets (which must be held by one or more Indigenous groups in whose territory the project is located). Proposals that do not provide confirmation of a minimum 25% First Nations equity ownership will be disqualified from the Power Call. Indigenous equity ownership in a proposed project must be held by the participating First Nation for at least three years post-COD.

— **Additional Equity Ownership**: Proposals will be given credit for additional Indigenous equity ownership beyond the 25% minimum eligibility requirement up to 51% (C$0.125/MWh for each percentage point between 26% and 49%, an additional $0.40/MWh for projects with 50% Indigenous ownership, and an additional $0.60/MWh for projects with 51% Indigenous ownership, up to maximum C$4/MWh for 51% Indigenous equity ownership).

— **Other Economic Benefits**: Proposals will receive a C$1/MWh credit if supported by a letter from one or more Indigenous group in whose territory the project is located, who are not equity owners of the proposed project, confirming that additional economic benefits (other than equity ownership) have been or are to be received.

— **Evaluation Methodology**: To evaluate the above criteria**,** BC Hydro is planning to develop and apply a First Nations benefits adjuster, which will reduce the adjusted bid price for project proposals that fit certain criteria.

We note that the above criteria are not final but were published by BC Hydro as a draft proposed model, which BC Hydro noted was provided "solely for the purpose of advancing without prejudice discussions during engagement sessions with First Nations."

The structures of equity ownership to be used by Indigenous project owners remain to be seen. Use of specially created classes of preferred equity to confer economic benefits more akin to a royalty or revenue-sharing agreement is expected to be less widespread than in previous BC Hydro calls for power. In response to BC Hydro's consultation regarding the Power Call, the B.C. First Nations Energy and Mining Council (BCFNEMC) laid out a **preferred model of equity ownership in project entities** with the following characteristics:

— **Grant:** 35% of the equity in the relevant project entity with the below characteristics would be granted to the relevant Indigenous group by the project proponent.

— **Structure:** a unique class of preferred equity in the project entity.

— **Dividends:** entitlement to dividends that match (on a forecast basis) annual distributions provided to the most remunerative class of equity in the project entity.

— **Retained Equity:** a pro rata claim to any retained equity within the project entity with the highest priority on dissolution.

— **Board Representation:** holders of this class of equity would be entitled to elect the number of directors to the board of the project entity equal to the class's pro rata share of total outstanding equity, which directors would have rights equal to all other directors on the project entity's board.

— **Capital Contribution:** this class of equity would have no capital contribution obligations attached to it.

In their proposal, the BCFNEMC also laid out a non-equity option for Indigenous project ownership that would require project proponents to provide annual cash payments in lieu of equity ownership equal to the return on a notional equity holding of 35%. This payment would reflect a return on equity equal to at least 200 basis points above the BCUC's benchmark allowed return on equity (using an assumed capital structure of 40% equity), applied to all project capital (including generation and interconnection facilities). The BCFNEMC's proposed equity ownership and non-equity ownership models also include an option for Indigenous groups to purchase up to an additional 15% equity in the relevant project entity using their own funds or funds provided through government grants or loans, including from the Canada Infrastructure Bank.

Groups formed by multiple Indigenous nations, such as the recently announced K'uul Power, composed of 11 First Nations from northwest B.C. working in collaboration with 11 more First Nations, are expected to play a more prominent role in this Power Call than in previous calls. K'uul Power has a stated mandate of employing a Nation-driven approach to fast-track individual Nations' review and decision-making regarding potential ownership and development of energy infrastructure.

In elaborating on their conception of equity participation in BC Hydro's proposed twinning of the Northwest Transmission Line, K'uul Power offered helpful discussion of the equity ownership model that may come to inform Indigenous equity ownership of projects selected under the Power Call. Similar to the BCFNEMC's proposed equity model for clean power projects, K'uul Power has called for "real" equity in the entity that would own the expanded Northwest Transmission Line. Such "real" equity would entitle K'uul Power, as a joint owner with BC Hydro, to make decisions regarding the design, construction and operation of transmission assets, as well as the right to sell the use of its portion of the line's transmission capacity. The jointly owned transmission infrastructure would be leased to BC Hydro, which would operate the transmission line as part of its integrated network and generate further revenue for K'uul Power as an equity holder. K'uul Power contrasted this "real" equity ownership model with one based on "synthetic" equity, under which the new transmission line would be wholly owned, designed, constructed and managed by BC Hydro and would entitle the Indigenous equity holders to a notional share of the assets and an economic return commensurate with owning a public utility asset, which K'uul Power rejected, asserting that such a "synthetic" equity model fails to deliver the full suite of benefits inherent to equity ownership.

Such Indigenous-driven equity ownership concepts will likely inform BC Hydro's design and continued Indigenous consultation regarding the Power Call and beyond. In BC Hydro's First Nations engagement workshops that concluded on November 30, 2023, BC Hydro discussed minimum hold periods for Indigenous equity and requested feedback from participating First Nations on whether they would prefer a minimum equity hold period or no equity hold period. In the Consideration Memo and the Draft RFP, BC Hydro confirmed that the Power Call would include a three-year post-COD holding period for Indigenous equity ownership. The characteristics and structures of Indigenous equity ownership models under the Power Call thus continue to be discussed and are not expected to be finalized until BC Hydro's design of the Power Call is more advanced.

Funding to support Indigenous participation in the clean energy sector has increased, alluding to the potential for Indigenous groups to be a primary driver of economic activity in the Power Call, both through project development and through the procurement of necessary services. The B.C. government **announced** C$140 million in funding for the B.C. Indigenous Clean Energy Initiative (BCICEI) to support Indigenous-led projects, some of which may not otherwise be competitive owing to their smaller size. The **BCICEI**, which provides funds to support and build capacity within Indigenous communities developing clean energy projects, is funded by the Canadian government and the province's **CleanBC initiative** and is managed through the **New Relationship Trust**. Further, the **First Nations Clean Energy Business Fund** (FNCEBF) was established under the *CEA* to facilitate Indigenous clean energy project development. The FNCEBF provides Indigenous groups with capacity funding up to a limit of C$50,000 per group to engage in project planning activities and business negotiations, equity funding up to a limit of C$500,000 per group to invest in clean energy project ownership, and a portion of provincial government revenues generated from Crown resources licensed for use in clean energy projects. In recognition that the clean energy landscape in the province has changed drastically since the inception of the FNCEBF, the C$50,000 capacity funding limit per group has been reset for the next round of FNCEBF applications, due in April 2024. Such funding will give greater latitude to Indigenous groups to develop projects in their preferred fashion.

EPA RENEWALS

Since our last publication, BC Hydro has made the form of **EPA renewal** (Specimen Renewal EPA) available to the public. The key commercial terms of the final draft EPA renewal term sheet that we summarized in **our publication last year** have been incorporated into the Specimen Renewal EPA. Additionally, as we noted last year, certain terms proposed by BC Hydro in their final draft EPA renewal term sheet differed from previous EPA forms used by BC Hydro. These terms, which BC Hydro has since stated are to BC Hydro's benefit, have largely been incorporated into the Specimen Renewal EPA and a summary of such BC Hydro-friendly terms is set out below:

- BC Hydro is not obligated to accept delivery of energy or make payments to an IPP during events involving force majeure, emergencies, system constraints, turndown periods, failure of suppliers to comply with project standards, and disconnection from the BC Hydro system to the extent such disconnection is not caused by BC Hydro;
- IPP sellers cannot sell power or any environmental attributes thereof to any party other than BC Hydro without BC Hydro's consent, even during periods when BC Hydro is relieved of its obligation to accept delivered energy;
- BC Hydro has the right to curtail deliveries of power for any reason other than an emergency condition, provided BC Hydro will pay for deemed energy that could have been delivered by the seller during curtailments due to BC Hydro system constraints in effect for more than an aggregate of 72 hours in a month; and
- if the seller is in material default and BC Hydro exercises its termination right, the seller must pay a termination payment equal to the greater of:
  - an amount equal to the positive amount, if any, by which BC Hydro's economic losses and costs exceed the aggregate of BC Hydro's gains from the termination; and
  - C$4,000 x plant capacity x years remaining before the EPA expires. No payment is owing by BC Hydro if the seller terminates for any reason.

Renewals for EPAs Expiring in 2026 and Beyond

Notwithstanding the EPA renewal terms favouring BC Hydro discussed above, IPPs with EPAs expiring prior to April 1, 2026, have been active in renewing their EPAs through BC Hydro's EPA Renewal Program. In total, **19 EPAs** for IPP generation facilities ranging in nameplate capacity from 0.2MW to 50MW are set to expire before April 1, 2026. BC Hydro has now entered into six new long-term EPAs with IPPs, representing roughly two-thirds of the total nameplate capacity available from the 19 expiring EPAs. All six renewed EPAs are currently **before the BCUC** for approval under s. 71 of the *Utilities Commission Act* (British Columbia), and a final determination is expected in early 2024.

BC Hydro's revised energy forecasts in their 2023 Updates assume broad renewal of EPAs expiring in the short to medium term, suggesting appetite from BC Hydro to leverage existing assets and remain in business with currently active IPPs. It is understood that the IPPs who sell power to BC Hydro under the remaining 13 EPAs set to expire before April 1, 2026, have been or will be offered opportunities to participate in the EPA renewal process upon the same terms as those offered for the six EPAs currently being renewed. BC Hydro has also indicated it intends to renew EPAs expiring after April 1, 2026, on a cost-effective basis, which may include continuing market-price-based renewal offers for those EPAs, stating in the 2023 Updates that there are 15 existing clean or renewable facilities that produce approximately 1,200 GWh/year with EPAs that expire between April 1, 2026, and April 1, 2030. For planning purposes, BC Hydro has assumed that each of these EPAs will be renewed. BC Hydro also estimates that existing IPPs already connected to the provincial power grid have capacity representing approximately 700 GWh per year of additional power available for sale to BC Hydro. BC Hydro anticipates that it can acquire this energy prior to fiscal 2029 through bilateral negotiations with individual IPPs, provided such acquisitions can be cost effective.

Alternatives to BC Hydro

Whether all IPPs with expiring EPAs will renew their agreements with BC Hydro is unclear. Given the current regulatory framework in B.C., IPPs have limited options for selling their power elsewhere. They may sell to Powerex, BC Hydro's trading arm, but Powerex does not typically enter into long-term fixed-price contracts. IPPs may sell power directly to a third-party customer using privately owned transmission infrastructure (retail sales to third parties in B.C. using BC Hydro's transmission infrastructure is prohibited by virtue of Direction No. 8 to the BCUC issued pursuant to the *Utilities Commission Act*), but, absent an exemption, this would result in any such IPP being subject to full regulation by the BCUC as a public utility under Part 3 of the *Utilities Commission Act* and entail utility-style rate-setting and robust regulatory compliance. Lastly, IPPs could consider exporting power to third-party customers outside of B.C.; however, in the case of export to the United States, the IPP would be required to obtain a federal electricity export permit from the government of Canada.

SITE C UPDATE

BC Hydro's Site C Clean Energy Project will be the third dam and hydroelectric generating station on the Peace River in northeastern B.C. Once complete, Site C will provide 1,100 MW of capacity and produce approximately

5,100 GW hours of energy per year. Construction on Site C began in July 2015 and, as of November 2023, Site C was approximately 80% complete and on track for a 2025 in-service date, with a total budget of C$16 billion, nearly double the original C$8.775 billion budget approved in 2014.

Key construction milestones in 2023 included the completion of the earthfill dam in July, the conversion of one of the tunnels that currently diverts the Peace River around the dam site, necessary to enable reservoir filling to occur, the completion of the Highway 29 realignment and the substantial completion of reservoir clearing.

BC Hydro had been progressing on the basis of having the option of starting reservoir filling in the fall of 2023, one year earlier than scheduled. However, in view of some remaining critical work areas and the onset of winter conditions, BC Hydro elected to maintain the original approved project schedule, which contemplates the first generating unit being placed in service by December 2024 and all six generating units in service by the end of 2025. Drought conditions in northern B.C., including persistently low precipitation, have led to below-average reservoir levels at many BC Hydro generation facilities and may impact the timeline for filling the Site C reservoir.

CLEANBC PLAN UPDATE

The B.C. government continues to advance its climate goals under the banner of **CleanBC**, the climate action plan introduced in 2018 that aims to reduce the province's greenhouse gas (GHG) emissions by 40% below 2007 levels **by 2030**.

In its **2023 Budget and Fiscal Plan**, the B.C. government announced that starting April 1, 2024, B.C. will transition to a **new carbon pricing model**, a "made-in-B.C." **output-based pricing system** (BC OBPS) for large emitters such as pulp and paper mills and oil and gas operations, under which performance-based emissions limits will be established and emissions in excess of the limits will be priced based on required reporting at the end of each year. Credits will be issued to facilities with emissions under their annual emission limit, which, along with other offsets, can be applied against payments owing in other years. BC OBPS will be mandatory for facilities that emit over 10,000 tCO_2e per year, and it will replace the current system that requires companies to pay the carbon tax and then apply for industrial incentive payments under the **CleanBC Program for Industry**. A portion of revenues from BC OBPS will be directed to the **CleanBC Industry Fund**, which funds projects designed to reduce greenhouse gas emissions from large industrial operations.

As of April 2023, B.C.'s carbon tax was **C$65 per tonne**, and in the 2023 budget, the B.C. government announced that it will increase annually by C$15 per tonne until it reaches C$170 per tonne in 2030, aligning with **federal carbon pricing requirements**. To offset the effect of these increases on British Columbians, the B.C. government has planned annual increases to the maximum annual **climate action tax credit available to individuals**.

The B.C. government has also continued to make investments in the **CleanBC Go Electric Program**, which is focused on shifting the province's transportation habits to electric vehicles with incentives to reduce electric vehicle costs for individuals and businesses, committing C$100 million to the program over the next three years. Its **Commercial Vehicle Pilots Program** supports businesses based in B.C., along with non-profits and certain public entities, in their deployment of commercial zero-emission vehicles, including not just cars, but rail, marine and aircraft. The province is also funding a new **B.C. Hydrogen Office** to advance hydrogen projects and make continued investments in the CleanBC **Active Transportation Strategy**, which supports community-specific active transportation networks and aims to double the percentage of trips taken with active transportation by 2030 and reduce vehicle transportation.

CleanBC is not without its detractors. In August 2023, the Business Council of British Columbia released a **report** claiming that the B.C. government's own modelling indicated that implementing the CleanBC plan will slow B.C.'s economic growth to the slowest pace on record and shrink the B.C. economy by C$28.1 billion by 2030. Meanwhile, B.C. United party leader Kevin Falcon has stated that if elected, **he would abandon CleanBC**. In **last year's publication**, we noted that in March 2022, the Sierra Club of B.C. had filed a petition in the B.C. Supreme Court alleging that the B.C. government failed to deliver a **2021 annual climate change accountability report** that met requirements set out in the B.C. ***Climate Change Accountability Act*** (CCAA) by not including plans to continue progress toward meeting B.C.'s targets set for 2025, 2040, 2050 and the oil and gas sector target set for 2030. In **a judgment delivered in early 2023**, the Honourable Justice Basran found that the question of whether a plan complies with statutory requirements is a matter of law and is therefore justiciable, but also found that, on a standard of reasonableness, the Minister had reasonably complied with the statutory reporting requirements of the CCAA, and he dismissed the Sierra Club's petition. Nonetheless, the finding that courts can rule on the government's compliance with reporting requirements **may open the door to further litigation** seeking to hold governments accountable for compliance with their obligations under climate change statutes.

LNG UPDATE

In the past year, certain clarity was provided for proposed liquefied natural gas (LNG) projects in B.C.

There have been ongoing questions and concerns as to whether the approval of any new LNG projects in B.C. can be compatible with the province's **climate goals and targets** to reduce greenhouse gas emissions, which requires new LNG facilities to achieve net-zero emissions by 2030. On March 14, 2023, the B.C. government introduced a new **energy action framework**, which attempts to address these concerns by proposing new requirements for future LNG facilities and B.C.'s oil and gas industry participants to align with the province's emissions-reduction goals. The framework:

— requires all proposed LNG facilities to have a credible plan to achieve net-zero emissions by 2030 in order to proceed through the environmental assessment process;

— puts in place a regulatory emissions cap for the oil and gas industry to ensure B.C. meets its 2030 emissions-reduction target for the sector;

— establishes a clean energy and major projects office to fast track investment in clean energy and technology and create good, sustainable jobs in the transition to a cleaner economy; and

— creates a BC Hydro task force to accelerate the electrification of B.C.'s economy by powering more homes, businesses and industries with renewable electricity.

Shortly thereafter, B.C. issued its **Oil and Gas Emissions Cap Policy Paper in July 2023**. The paper sets out examples of how LNG may meet zero emissions by 2030, such as adopting best-in-class technology and offsetting emissions through verified carbon-offset projects.

LNG Canada

In July 2023, **LNG Canada** — a joint venture between Shell Canada, Petronas, PetroChina, Mitsubishi Corporation and KOGAS — **reported** that its Phase 1 construction was 85% complete. Its associated Coastal GasLink pipeline **finished construction** in November 2023, marking another milestone in the development of LNG Canada's facility. The pipeline is set to enter its testing phase before transmission of gas to Kitimat, B.C., can begin.

LNG Canada's Phase 1 is scheduled to begin shipments to Asia in 2025, with the goal of exporting 14 million tonnes of LNG per year. This C$40-billion project is located in Kitimat, B.C., and was the first large-scale LNG export facility to announce a **final investment decision** in the province. The terminal is being built on the head of the Douglas Channel, on the traditional territory of the Haisla Nation.

A final investment decision has not yet been made for Phase 2 of LNG Canada, which would double the exporting capacity of the facility from 14 million to 28 million tonnes per year. LNG Canada and BC Hydro are reported to be making progress in their discussions about the prospect of increasing the hydroelectricity capacity that would be required if Phase 2 switches to electric motors to power its liquefaction compressors. However, no final plans have been made to build the required infrastructure in time to make the Phase 2 build-out electric.

Cedar LNG

The B.C. government granted the proposed **Cedar LNG** project its **environmental assessment certificate** in March 2023. Cedar LNG is a Haisla Nation majority-owned partnership with Pembina Pipeline Corporation. This C$3-billion project is also proposed to be located in Kitimat, B.C., on Haisla Nation-owned land, and would be supplied with natural gas from the now-complete Coastal GasLink pipeline. If built, Cedar LNG would produce approximately three million tonnes of LNG per year. At the time of writing, a final investment decision for Cedar LNG has not yet been made. However, Cedar LNG's final investment decision is expected to come during the first quarter of 2024, with commercial operations beginning in 2027.

Notably, B.C.'s energy action framework was announced after the approval of the Cedar LNG project, such that it will not be subject to the more onerous emissions and net-zero requirements that will apply to those LNG facilities that are currently in, or will undergo, the environmental assessment process. The Cedar LNG project will still be subject to certain ongoing terms, conditions and requirements set out in its environmental assessment certificate and the impact assessment decision.

Recent significant milestones for the Cedar LNG project include the signing of a **heads of agreement** in November 2023 with Samsung Heavy Industries (SHI) and Black & Veatch (B&V) to reserve shipyard capacity for LNG modules construction, as well as the **selection in January 2024 of SHI and B&V** to provide engineering, procurement and construction services for the design, fabrication and delivery of the project's floating LNG production unit (subject to the final investment decision).

Woodfibre

The **Woodfibre LNG** project located near Squamish, B.C., is now under construction. Woodfibre LNG is co-owned by Pacific Energy Corp. (70%) and Enbridge (30%) and is expected to export 2.1 million tonnes per year of LNG. The project, including its compressors, will be powered by renewable hydroelectricity and is stated to be the cleanest LNG facility in the world. The project is set to begin operations in 2027 in Howe Sound and plans to meet net-zero emissions by the time operations commence.

FortisBC commenced construction in August 2023 of the **Eagle Mountain pipeline**, a 38-km long, 24-in diameter pipe to supply gas to the Woodfibre LNG project.

Ksi Lisims

In March 2023, the Nisga'a Nation-led C$10-billion LNG project **Ksi Lisims** received the **go-ahead** to enter B.C.'s environmental review process. The Ksi Lisims LNG project is a partnership that includes the Nisga'a Nation, Western LNG and a group of natural gas producers called Rockies LNG. The project aims to export 12 million tonnes of LNG per year, making it Canada's second-largest LNG export facility. Additionally, Ksi Lisims LNG has contracted with Calgary-based TC Energy Corp. to support its plans to design the revised Prince Rupert Gas Transmission pipeline. A significant recent milestone for the Ksi Lisims LNG project, **announced** on January 8, 2023, was the signing of a 20-year offtake agreement with Shell Eastern Trading Pte Ltd. for the sale and purchase of LNG from the project.

B.C.'s Environmental Assessment Office (the EAO) has requested that Ksi Lisims LNG provide "credible plans" to attain net-zero emissions by 2030 to comply with the energy action framework. Accordingly, Ksi Lisims plans on using floating facilities, with hydroelectricity powering motors for compressors in the liquefaction process. While it remains to be seen how any changes to the federal impact assessment process coming out of the ***Reference re Impact Assessment Act*** (see **Key Developments in 2023 — Constitutional Challenges to Federal Environmental Oversight**), it has been provisionally agreed that, at the request of the EAO, the federal impact assessment process will be provincially led by the B.C. regulator as a collaborative assessment with the federal government.

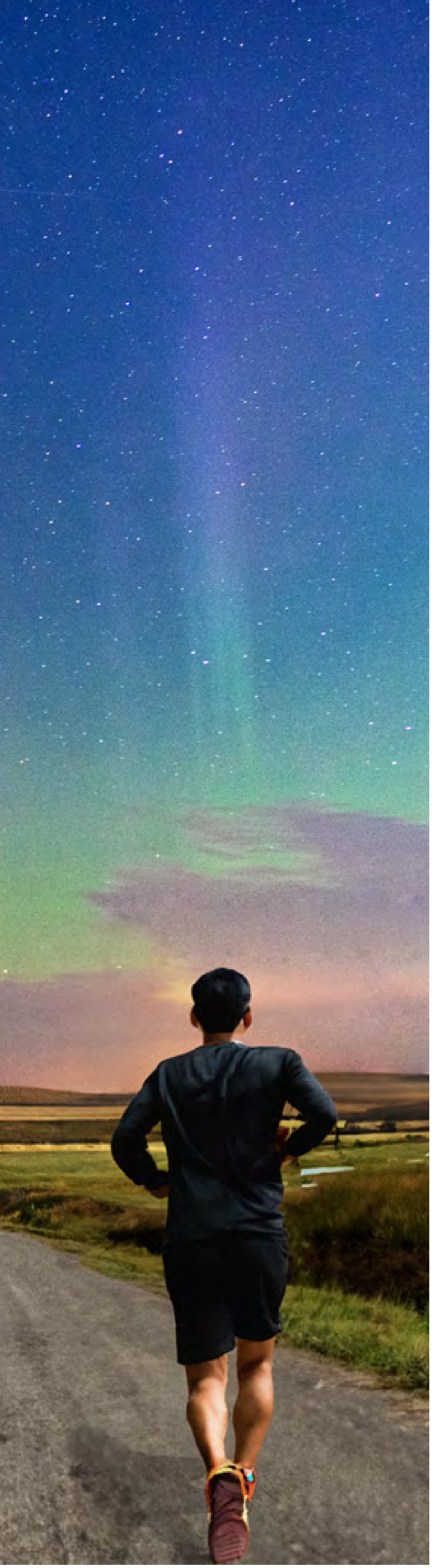
The discussion above regarding K'uul Power under the "First Nations Economic Participation" subsection of this chapter with respect to the Power Call is also highly relevant to the electrification of the Ksi Lisims LNG project, as the Nisga'a Nation is one of the First Nations involved in K'uul Power.

Tilbury

Tilbury LNG is an expansion of an existing FortisBC facility, located on Tilbury Island in Delta, B.C. FortisBC is in the early planning stages to complete Phase 1 of the expansion to its liquefaction capacity, which could be in service as early as 2025. In addition, the Tilbury Jetty Limited Partnership, to be jointly owned by Fortis LNG Jetty Limited Partnership and Seaspan, has filed an application for environmental assessment for a marine jetty adjacent to the Tilbury LNG facility.

ALBERTA
REGIONAL OVERVIEW

Authors: Brian Bidyk, Derek Baker, Kerri Howard, Kimberly Howard, Thomas McInerney, Connor O’Brien, Ashley Wilson, Jonathan Brisebois, Lindsay Nguyen and Riley Thackray



Alberta Regional Overview

INTRODUCTION/ALBERTA ELECTION

This past year was a busy year for the Alberta energy industry. With the continued push to achieve emissions reductions nationally and furthering the net-zero transition, while ensuring stable and reliable energy generation, the energy transition and industry policy and regulation have been the primary focus for stakeholders in Alberta.

On May 29 2023, Alberta held its general election, where the United Conservative Party (UCP), under the leadership of Danielle Smith, was re-elected with a reduced majority. The UCP focused on a number of key issues during the campaign, among these priorities being continued support for a strong oil and gas industry. The UCP has largely opposed many of the federal emissions reduction initiatives being imposed upon industry stakeholders, many of which will be discussed further below in this chapter and throughout this publication.

With continued debate over constitutional rights, the ability to regulate the energy industry, co-operative federalism and Alberta's potential use of the *Sovereignty Within a United Canada Act* (Alberta) to limit the effect of certain federal regulations, 2024 is sure to be another year of change in Alberta.

REGULATORY PAUSE ON RENEWABLES

On August 2, 2023, the government of Alberta (the Province) issued **order-in council** (171/2023) (the Order) pursuant to which the Alberta Utilities Commission (AUC) was ordered to inquire into and report to the Minister of Affordability and Utilities (the Minister) on the ongoing economic, orderly and efficient development and operation of electricity generation in Alberta (Inquiry).

To facilitate the Inquiry, the Province further issued a second **order-in-council** (172/2023), enacting the ***Generation Approvals Pause Regulation*** which restrains the AUC from granting approvals with respect to any hydro development or power plant that produces renewable electricity until February 29, 2024, subject to certain exceptions (Renewables Pause). The Province has **stated** the pause directly affects 13 projects that at the time of the announcement, were before the AUC seeking approval. The AUC then **announced** that during the Renewables Pause it will continue to process applications up to the approval stage for new hydro developments and power plants that produce renewable electricity but will not be issuing decision reports for such applications.

To facilitate applications submitted during the Renewables Pause, the AUC **introduced** new, interim information requirements relating to agricultural land, viewscapes, reclamation security and land use planning for new power plant applications, including wind, solar, thermal, hydroelectric and other power plants. For a summary of these changes, see Noteworthy AUC and ISO Rule Changes below in this chapter.

To fulfil the requirements set out in the Order and to guide the AUC's Inquiry, the AUC **announced** the scope and process of its Inquiry, stating that it would be broken into two modules, "Module A" and "Module B." Module A is intended to review the role of municipal governments, and others, in land impact issues and more specifically review the following:

— the considerations in respect of the development of power plants on specific types or classes of agricultural or environmental land;

— the considerations in respect of the impact of power plant development on Alberta's pristine viewscapes;

— the considerations in implementing mandatory reclamation security requirements for power plants; and

— the considerations for development of power plants on lands held by the Crown in Right of Alberta.

In undertaking its review of the items specified in Module A, the AUC held oral and reply submissions in mid-December, with written submissions and comments on certain key issues which were submitted at the end of November 2023.

The scope of Module B is intended to review the impact of the increasing growth of renewables to both generation supply mix and electricity system reliability. In furthering its inquiry into these matters, the AUC has commissioned two **expert reports** that will cover the following scopes:

— A review and assessment of prior studies that will evaluate the evolution of Alberta's electric system from a technical and/or economic perspective in order to inform reliability and affordability questions. Further, following stakeholder engagement, develop a technical, simulation-based assessment of future wholesale market fundamentals under the current energy market design over the long term to evaluate future system reliability and consider electric utility bill impacts for retail customers.

— Using targeted stakeholder engagement and other means, gauge current perception of Alberta's power market by relevant generation developers (incumbent and non-incumbent) and sources of capital to review the attractiveness of Alberta's market structure changes, and the appetite for merchant power risk.

In addition, this report will identify the drivers behind stakeholder perception of Alberta's power market.

The expert reports and oral and written submissions covering the above will guide the AUC's report, which will summarize its findings and is expected to be submitted to the Minister no later than March 20, 2024.

TRANSMISSION POLICY REVIEW

The significant changes to Alberta's electricity market in recent years due to the diversification of generation, new technologies and climate policy has provoked the Province to undertake a review of the policies which govern Alberta's transmission market (Review). In October 2023, the Province **published** a green paper, entitled *Transmission Policy Review: Delivering the Electricity for Tomorrow* (the Green Paper), which seeks to achieve three objectives:

1. **Affordability**: The Province has stated that affordability remains a paramount priority of Alberta's electricity market, noting that transmission costs for consumers in Alberta have increased by over 500% since 2004. To achieve affordability, the Province is looking to address the root causes of high transmission costs while ensuring long-term stability as the energy market continues evolve and diversity.

2. **Reliability**: In a continued shift away from high-emitting generators, the Province is focused on: (i) ensuring sufficient generation to meet demand; (ii) maintaining the ability to transmit such energy; and (iii) ensuring the system is robust in terms of power quality and its ability to respond to changes in supply and demand.

3. **Decarbonization**: As Alberta pushes to achieve its **goal** of a carbon-neutral grid by 2050, to aid broader economic decarbonization efforts, any changes to transmission policies will be considered in light of this goal.

The success of achieving these objectives will be founded on the following principles:

- **Maintaining regulated transmission**: As Alberta's transmission system is currently operated as a regulated monopoly, the Province has acknowledged that it is a foundational principle that the transmission system continues to be operated in a regulated manner.
- **Maximizing efficiency**: A key to maximizing efficiency is through the use of current infrastructure and ensuring that any new infrastructure is minimized to reduce costs. The Province noted that using the current systems to incentivize generators to locate near consumers or existing transmission capacity will reduce the end costs to ratepayers.

Through these objectives and principles, the Review is seeking feedback on several policy issues, some of which the Province has already sought feedback on from industry stakeholders, while others are broader policy issues for consideration. The Province is seeking input on the following:

Generating Unit Owner's Contribution

Generators make a financial contribution to the Alberta Electric System Operator (AESO) at the time of connection, which is based on the generator's size, location and performance and is funded over time. This contribution is known as the generating unit owner's contribution (GUOC). Initially intended to serve as a locational signal for new generators, the Province notes that the GUOC amount is set at an insufficient level to incentivize generators to site close to existing transmission. The Province is considering amendments to the *Transmission Regulation* (Regulation) to ensure that the GUOC amount is set at a level that will provide sufficient locational price signals to drive the efficient use of existing transmission capacity and, in turn, result in reduced transmission costs for consumers.

Line Loss Calculations

Currently, generators are responsible for the cost of electricity that is lost as heat during its transmission along a line. The current policy is to provide an estimate of the loss factors for each site prior to the start of the year and then adjust such factors based on actual performance during the second quarter. The intention of this policy was to incentivize generators to locate in areas close to load, however, the associated line loss costs have failed to encourage generators to consider transmission impacts in choosing their location. The Province is considering alternative approaches to the current line loss methodology system, including a system-wide average or regional approach.

Non-Wires Solutions

The Regulation currently provides for tight boundaries on the use of non-wires solutions, providing investors with confidence that non-wires solutions will not distort market impacts. The Regulation provides the AESO with the flexibility to propose a non-wires solution to relieve congestion on the transmission system. However, in light of emerging technologies that can defer the need for additional wires, the Province has noted that there is an opportunity to broaden the use of non-wires solutions as a way of managing transmission costs.

Congestion Policy

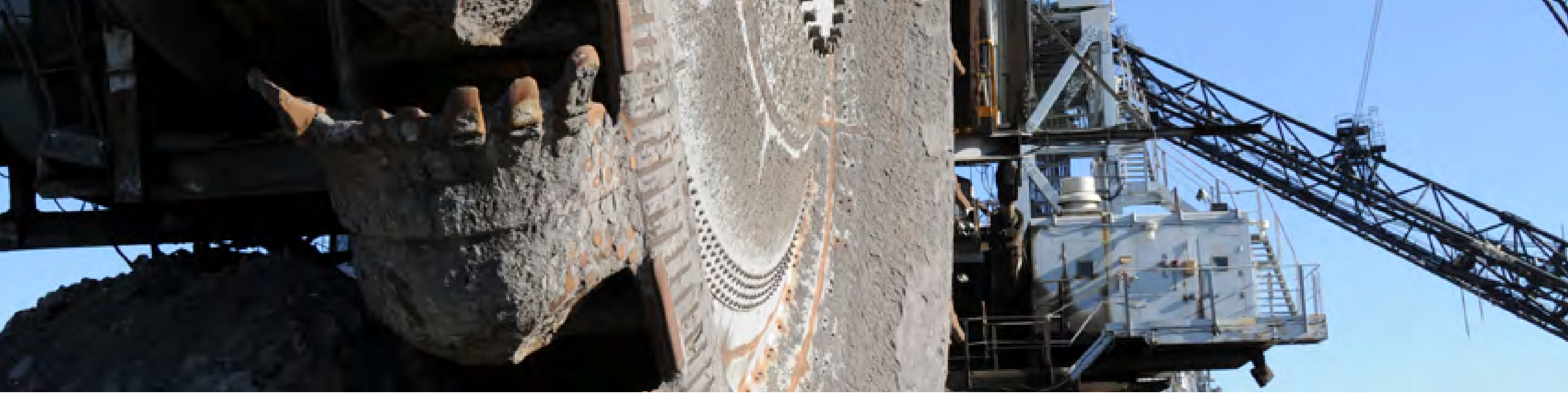
Alberta's transmission system does not assign transmission rights to market participants. Rather, transmission is allocated upon dispatch to participants based on consumption. As Alberta's market is based on a zero-congestion policy, due to recent changes in the supply mix making up the electricity market, there are increasing amounts of generation connected to the distribution system and a majority of new generation technologies rely on intermittent resources. The Province is seeking feedback on whether a move away from the zero-congestion policy to a subsequent planning policy is possible as a means of managing congestion.

Cost Allocation

The dispersion of costs paid for wires and ancillary services between ratepayers in the electricity system is how cost allocation is achieved. The Province is considering alternative policies that could offer Albertans a more appropriate and efficient allocation of wires costs to ensure that consumers are receiving the maximum possible benefits from transmission investments and incentivizing efficient use of the system, which in turn will minimize the growth of future wires costs.

Cost Allocation for Ancillary Services

Ancillary services are those additional electricity services that the AESO procures outside of the power pool to ensure that the system remains reliable. As the sole provider of system access, the AESO has indicated there is a need for more ancillary services in order to maintain overall system reliability. In light



of this need, the Province is considering reassigning costs based on cost causation to ensure the benefits are still being provided and that costs are internalized by those who give rise to them.

The Treatment of Interties

Transmission connections to other jurisdictions, known as interties, is an essential part of Alberta's competitive electricity market, allowing Alberta to import electricity when needed and export surplus energy, all to maintain reliability. Interties provide the AESO with flexibility to maintain system reliability by providing near immediate responses to generator outages and intermittent generation. The policies pertaining to interties — specifically with respect to future intertie developments and the need to balance such developments with fair, efficient and open competition outcomes in the wholesale market — are particular areas in which the Province is seeking feedback on.

In November 2023, stakeholders were encouraged to respond to questions posed by the Province in the Green Paper. The Minister will analyze the responses to determine the ideal path of action for Alberta's transmission policies.

KEY DEVELOPMENTS IN 2023

Regulatory Updates

AESO Net-Zero Pathways Report, the CER and Industry Reaction

Net zero and decarbonization goals and policies are at the forefront of both provincial and federal policy agendas and have been a founding principle for changes to the electricity market in many provinces, including Alberta. On June 27, 2022, the AESO released their **Net-Zero Emissions Pathways Report** (Net-Zero Report), which analyzed potential pathways to achieving net zero for Alberta by 2035. A key focus of the Net-Zero Report was the projection that although a net-zero electricity grid in Alberta is possible by 2035, a significant amount of investment is going to be required to meet this goal. In comparison to its own report, ***Long-term Outlook*** (LTO) released in 2021, which set forth a gradual approach to net zero in Alberta, the AESO estimated in the Net-Zero Report that an additional C$44-52 billion in investment would be required to achieve net zero in Alberta by 2035.

The release of the ***Clean Electricity Regulations*** (CER) in August of 2023 has added complexity to achieving the net-zero goal. The president and CEO of the AESO **stated** in September of 2023 that it is "not feasible" to achieve net-zero emissions in Alberta based on modelling that included the draft CER due to supply adequacy and reliability challenges from 2035 and beyond for Alberta's power system.

In June of 2023, the Pembina Institute released its own pathways to net-zero report, ***Zeroing In: Pathways to an affordable net-zero grid in Alberta*** (Pembina Report), which suggested that the investment required to achieve net zero by 2035 in Alberta would be C$22 billion less than the LTO, as suggested in 2021, and between C$27-28 billion less than the AESO's projected net-zero scenarios. These cost saving projections are driven by the deployment of lower-cost solar and wind generation that displaces large amounts of existing natural gas generation. Importantly, the Pembina Report was released prior to the CER and did not take into account any of the CER findings.

The Alberta government has indicated it intends to enact the Sovereignty Act in response to the CER as discussed further in our **Environmental Law** chapter below.

Update on Alberta's CCUS Hubs

In May 2021, **Alberta Energy** announced a new **competitive bid process** under which it will issue rights for carbon sequestration. The process focuses on the development of strategically located carbon sequestration hubs, allowing for additional volumes and multiple sources of carbon dioxide (CO_2) to be stored and avoiding stand-alone injection operations. Following two request for full project proposals for carbon sequestration hubs (RFPP), 25 projects were selected to explore how to safely develop their carbon storage hub and, following a successful evaluation, demonstrate how the proposed project can provide permanent storage. Following that, companies will have the opportunity to apply to the Province for the right to inject captured CO_2.

The Province, together with the various regulatory bodies, has worked to establish the framework and legislative scheme governing carbon capture, utilization and storage (CCUS) in Alberta. The initial application and permitting process for CCUS projects in Alberta can be divided into four stages:

1. selection through the competitive carbon sequestration tenure management process;

2. initial acquisition of subsurface and surface rights (through evaluation permits and carbon sequestration lease agreements (SLAs));

3. discretionary activity review and potential environmental impact assessments; and

4. regulatory approvals, including from the Alberta Energy Regulator (AER) through its injection scheme and pipeline and injection well licences.

Several project proponents are currently in discussions with the Province to negotiate the terms of the SLAs, which are agreements between the proponents and the Province that provide the successful proponents with the **right to**, among other things, inject captured CO_2 into subsurface formations and place requirements on the project proponents to manage the development of the hub and ensure the efficient use of pore space. The SLAs are intended to give the proponents the right to inject captured CO_2, while providing open access and affordable use of the hub and provide just and reasonable cost recovery to the agreement holders.

Recent AUC Decisions

AUC Decision 27388-D01-2023 (New Performance-Based Regulation)

On October 4, 2023, the AUC released **Decision 27388-D01-2023** as guidance on its third generation of performance-based regulation (PBR). One of the primary roles of the AUC is to ensure safe and affordable gas utility service through performance-based regulation in Alberta. The new PBR terms will be implemented for the 2024 to 2028 period and apply to ATCO Electric Ltd., FortisAlberta Inc., ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., ATCO Gas and Pipelines Ltd. and Apex Utilities Inc.

The PBR encourages efficiency, lower costs and set rates by promoting competition-like behaviour. Utilities that operate more efficiently, enjoy higher returns, leading to lower rates for customers. The changes introduced by the new PBR terms include a pilot alternative remuneration scheme, additional benefit sharing provisions and an asymmetric two-tiered earnings sharing mechanism.

Recent Denials of Renewable Energy Applications

Recently, the AUC has rejected several applications for renewable energy projects on the basis that they pose risks to Alberta's wildlife and landscape or are not in the public interest.

On April 20, 2023, the AUC **rejected** an application for the construction and operation of a solar plant and substation. The proponent claimed the project would have public benefits such as reduced greenhouse gas emissions and local economic advantages and was in the public interest. The AUC determined that there were potential positive socioeconomic effects on the Cold Lake First Nations and reconciliation opportunities as the proponent was working with the First Nation to secure an ownership interest in the project. However, the AUC denied the application after expressing concerns over high bird mortalities and adverse impacts on the Frank Lake Important Bird and Biodiversity Area, as well as concerns over the associated social and environmental values that were presented by the project.

The AUC **bifurcated** an application for the construction of a solar plant and associated substation and an application for the construction of a telecommunications tower and modifications to an associated transmission line. In its decision, the AUC approved the application for the construction and operation of the solar power plant and associated substation, as such projects were in the public interest. However, it denied the application for the construction of the transmission line and alterations to a subsequent transmission line and their connection to the solar power plant. The AUC denied the application on the basis of vague routing methodology, inadequate consideration of safety near a fuel terminal and residential impacts on an alternative route within close proximity to residences.

On July 20, 2023, the AUC **rejected** an application for the construction and operation of a solar project, connection to the distribution system and change in ownership on the basis that the project deviated from Alberta Environment and Protected Areas' **Wildlife Directive for Alberta Solar Projects**. It was determined the application was not in the public interest due to the project's location within 1,000 metres of a named lake and the increase in wildlife around the lake's area, making the project an unacceptable risk to migratory and water birds.

Noteworthy AUC and ISO Rule Changes

A summary of the noteworthy AUC and ISO Rule changes are outlined below.

Agency	Rule	Summary
AUC	*Rule 016: Review of Commission Decisions*	The AUC announced amendments to Rule 016 in Bulletin 2023-08. The amendments include: — the introduction of minimum information requirements for errors of fact and errors of mixed fact and law; — changing the standard of proof for errors of fact and mixed fact and law from a balance of probabilities to a palpable and overriding error; and — codifying the discretion of the AUC to dismiss a review application, with or without further process if: (i) the application does not comply with the minimum information requirements; or (ii) the application is outside the scope of permissible grounds for review.
AUC	*Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines*	To address the Province's concerns during the Renewables Pause, the AUC implemented interim information requirements for power plant applications, including wind, solar, thermal, hydroelectric and other power plants. The requirements include, among other things that: — **Agricultural Land:** applicants must detail earthworks plans, assess potential for co-locating agricultural activities in project design and list qualifications of agrologists involved in preparing or reviewing responses regarding agricultural land. — **Municipal Land:** applicants must verify compliance of the proposed power plant with municipal planning documents, including development plans, structure plans, land use bylaws and other municipal bylaws and identify and justify instances of non-compliance between the proposed power plant and relevant municipal planning documents. — **Viewscapes:** applicants must identify and detail pristine viewscapes, encompassing national parks, provincial parks, culturally significant areas and sites utilized for recreation and tourism that will be affected by the project. — **Reclamation Security:** applicants must describe the reclamation security program for the proposed power plant, including details on the standard to which the project site will be reclaimed to upon decommissioning, how the amount of the reclamation security was calculated, what form the reclamation security will take and how the beneficiary can access the security and constrains on such access. The interim requirements are in effect until further notice.

Noteworthy AUC and ISO Rule Changes

A summary of the noteworthy AUC and ISO Rule changes are outlined below.

Agency	Rule	Summary
AUC	*Rule 012: Noise Control (Rule 012)*	The AUC has sought two rounds of consultation on potential changes to certain provisions of Rule 012 to streamline and improve regulatory and adjudicative processes. Topics that the AUC is seeking feedback on include the definition of suburban and urban receptors, determination of suburban and urban permissible sound levels, milestones for establishing permissible sound levels at new dwellings and tonality evaluation. The AUC held a technical meeting in July 2023 to discuss feedback received and has not yet provided updates following the meeting.
AESO	*ISO Rule 203.6: Available Transfer Capability and Transfer Path Management*	Subsection 5(3)(b) was removed and s. 6(4)(a) was amended to eliminate the requirement that pool participants restate their available capability for interchange transactions in circumstances where an e-tag is curtailed by the Independent System Operator (ISO) or another transmission service provider. It was determined this requirement was unnecessary as the pool participant would either be repeating an instruction that was given by the ISO or that the ISO was already aware of. Subsection 5(4) was also removed to eliminate the requirement that pool participants restate the available capability of the interchange transaction when available transfer capacity limits are lowered after T-2.
AESO	*ISO Rule 202.6: Adequacy of Supply*	Subsections 2, 3 and 4 were amended to remove the specific methodologies and calculations for supply adequacy forecasts, real-time adequacy assessments and long-term adequacy metrics while maintaining the general requirements to conduct these forecasts and reports. Subsection 5 was added to provide that the AESO must publish the forecasts and reports set out in ss. 2, 3 and 4, along with details of the calculations and methodologies underlying such forecasts and reports and give 60 days' notice of any proposed changes to such calculations and methodologies and provide market participants an opportunity to provide feedback on the proposed changes. The new s. 7 adds a requirement that the ISO must publish a report on potential adequacy issues requiring preventative action prior to procuring services to address a potential adequacy issue.
AESO	*Energy Storage Rules*	Following the AUC's decision in June 2023, the AUC approved the Energy Storage ISO Rule Amendments which will come into effect on April 1, 2024. The rules as currently contemplated do not contemplate the integration of energy storage technologies to the interconnected electric system, which results in a lack of clarity as they apply to energy storage.

ALBERTA ENERGY REGULATOR BULLETIN UPDATES

Update on the Implementation of the Liability Management Framework

On November 16, 2023, the AER released **Bulletin 2023-41** regarding the ongoing implementation of the updated Liability Management Framework (LMF), which was initially announced in 2021, and replaces the Licensee Liability Rating (LLR) Program. The process to implement the new LMF has involved updating various regulatory instruments and establishing a new security framework under the *Oil and Gas Conservation Act*, which will aim to improve risk assessment, ensure fair responsibility for cleanup of active sites and streamline regulations. The new security framework will also consider factors beyond what was previously considered under the LLR Program, including the entire energy development life cycle and polluter-pays principle. The AER anticipates that further regulatory instruments will require updates as the LMF continues to be implemented and anticipates seeking feedback from stakeholders in 2024.

Directive 090: Brine-Hosted Mineral Resource Development

On March 1, 2023, the *Mineral Resource Development Act* came into force for brine-hosted mineral development. Subsequently, on March 2, 2023, the AER released **Directive 090: Brine-Hosted Mineral Resource Development** (Directive 090). Directive 090 completes the regulatory framework for brine-hosted mineral resource development and came into effect alongside the *Brine-Hosted Mineral Resource Development Rules* (BMR). Both the BMR and Directive 090 outline industry obligations throughout the life cycle of a brine-hosted mineral resource development. In addition, the BMR and Directive 090 introduce methods and standards unique to developing brine-hosted mineral resources while integrating the relevant regulatory tools from the oil and gas sector.

Directive 056 and Manual 012 – Geothermal and Brine-Hosted Mineral Resources Amendments

To enforce the regulatory framework for geothermal and brine-hosted mineral resources, the AER released **Bulletin 2023-09**, announcing revisions to *Directive 056: Energy Development Applications* (Directive 056) and *Schedules and Manual 012: Energy Development Applications, Procedures, and Schedules* (Manual 012). Directive 056 now covers licensing for geothermal and brine-hosted mineral development with Manual 012 integrating these resources while also providing guidance for public lands and liability management. Additionally, the revisions to both Directive 056 and Manual 012 include changes relating to licensing of carbon sequestration evaluation wells and carbon sequestration wells.

ABCA DECISION ON FOREST FIRE EQUIPMENT LOSS

On April 14, 2023, the Alberta Court of Appeal (ABCA) released an important decision in ***ATCO Electric Utilities Ltd v. Alberta Utilities Commission*** (ATCO Wildfires) regarding the treatment of costs associated with the destruction of utility assets from natural disasters, such as wildfires, and whether such costs are to be borne by the ratepayers or the utility. The decision from the ABCA distinguishes prior case law that established a distinction between the cost treatment of stranded assets that face "ordinary retirement" versus "extraordinary retirement" — costs associated with the latter were previously determined to be borne by the utility rather than the ratepayers.

ATCO Wildfires is an appeal of AUC Decision 21609-D01-2019 in which the AUC held that ATCO Electric Ltd.'s (ATCO) assets that were destroyed in the 2016 Fort McMurray wildfires could not continue to be depreciated in ATCO's regulated accounts, as such destruction amounted to "extraordinary retirement." Consequently, the undepreciated value associated with such destroyed assets was to be borne by the utility's shareholders rather than the ratepayers.

On appeal, the ABCA found the facts present in the ATCO Wildfires case were distinguishable from the prior case law, noting that when natural disasters arise, the question to be decided is not "where the ownership interest lies," but rather "whether it is just and equitable to continue to give the utility a reasonable opportunity to recover the costs prudently incurred … Wildfires are not a risk of property ownership, they are a risk of operating a utility in an environment subject to uncontrollable and unpredictable forces of nature." The decision was sent back to the AUC for further consideration and redetermination, noting that the determination that the rate-treatment of destroyed assets is within the discretion of the AUC, including what expenses can be included as recoverable costs and expenses and how stranded or unpredictably destroyed assets should be dealt with.

WHAT'S NEXT?

As we look to 2024, we anticipate a continued focus on government regulations and incentives in the energy transition space.

As both provincial and federal governments continue with the implementation of decarbonization regulations and policies, we expect to continue to see back and forth between the government of Alberta and the federal government, including with respect to revisions to the *Impact Assessment Act* (Canada), which was found earlier this year to be unconstitutional in part, as well as discussion and potential challenge to the newly announced federal oil and gas emissions cap-and-trade framework. In addition, following the government of Alberta's assertion that the draft CER is unconstitutional, it announced that it intends to invoke a resolution under the Sovereignty Act, directing certain provincial entities not to enforce or comply with the CER once in force, the effects of which will unfold into 2024.

We also expect to see continued support and incentives in the transition to clean energy, including the continued backing of CCUS. On November 28, 2023, the government of Alberta announced incentives for the development and integration of CCUS infrastructure and technology in Alberta, which includes the **Alberta Carbon Capture Incentive Program** (ACCIP) as discussed further below. The ACCIP will be eligible for facilities across various sectors including oil sands, oil and gas production, enhanced oil recovery production, petrochemical, power generation and more and will include a grant of 12 per cent for new eligible CCUS capital costs, which will be paid to operators in three installments over three years with portions of the funding coming from the Technology Innovation and Emission Reduction Fund. The ACCIP is expected to be available in spring 2024.

Following the AUC's report which is due to the Minister in March 2024, it is unclear what legislative or policy changes are to be expected, if any, or what the potential effects will be to the energy market in Alberta generally, including the lift or extension of the Renewables Pause.

ONTARIO REGIONAL OVERVIEW

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ONTARIO REGIONAL OVERVIEW

INTRODUCTION

The past year, 2023, has seen a commitment by the government of Ontario toward initiatives to further increase the production, transmission and generation of electricity. Building on its ***2022 Annual Planning Outlook Report***, in early 2023 the Independent Electricity System Operator (IESO) **engaged interested parties** to collect information prior to publishing its next *Annual Planning Outlook*. The IESO's 2024 Annual Planning Outlook will detail Ontario's future operational requirements, building on the Ministry of Energy's ***Powering Ontario's Growth*** report released in July 2023 in order to provide market participants with actionable information regarding potential investment opportunities using the resource adequacy framework.

PROCUREMENT UPDATES

The ***Powering Ontario's Growth*** report notes that **Ontario's population is expected to grow by two million people by the end of the decade** and that the government plans to build 1.5 million new homes. These and other factors give rise to the IESO forecasting that the province's power demand could double by 2050. The report states that the government intends to meet such electricity requirements through several initiatives, including future procurements. Some of these initiatives include:

- pre-development work for a new, large-scale nuclear power plant at the Bruce nuclear site;
- three additional small modular nuclear reactors at the Darlington nuclear site;
- three new transmission lines to power the conversion from coal to electric arc furnaces at Algoma Steel in Sault Ste. Marie as well as to accommodate growth in northeastern Ontario;
- pumped hydroelectric storage assessments; and
- planning for clean resource electricity competitive procurements.

In the dynamic landscape of Ontario's forecasted energy consumption, the present scenario underscores the necessity for a robust electrical infrastructure. With a current system capacity of **41,763 megawatts** (MW) annually, the 15 million residents of the province rely on substantial power supply to fuel their daily lives. However, the IESO's projections indicate an anticipated need to more than double Ontario's installed generation capacity to 88,393 MW by 2050 to meet forecasted increased demand. In addition to the above-listed initiatives, various other projects are being actively pursued to bridge the impending gap between supply and demand. Such projects are expected to encompass a spectrum of innovative technologies, sustainable energy sources and grid enhancement strategies. As a result of the government's policy announcements in the *Powering Ontario's Growth* report and directives issued by the Minister in connection with the report, the IESO has rescheduled the release of its next Annual Planning Outlook and Annual Acquisition Report to the first quarter of 2024 with a view to better integrate the contents of the two reports.

Despite the delay in the release of 2023 Annual Acquisition Report, 2023 had a number of significant developments that have rekindled the interest of investors in Ontario's power industry. In May 2023, it was announced that the Oneida Energy Storage Project had reached financial close with Canada Infrastructure Bank and had entered into a 20-year agreement with the IESO, marking a significant stride in bolstering Ontario's energy storage infrastructure. The project will be a **250 MW/1,000 MWh** battery energy storage facility, positioning itself among the largest projects of its kind worldwide when completed. The project is expected to effectively double Ontario's existing energy storage resources to an estimated 475 MW.

Ontario is also moving forward with 739 MW of new energy storage as the IESO announced the procurement of seven new storage projects arising from its Expedited Long-Term Request for Proposals (E-LT RFP) that was launched in 2022. These facilities will range from 5 MW to 300 MW and will assist in meeting the rising demand in the province and locally. As a sign of increased participation by Indigenous groups in Ontario's energy infrastructure, five of the seven projects have at least 50% of their economic interests owned by Indigenous groups. These storage facilities and Oneida's will add to system reliability by charging during off-peak hours and supplying energy back into the system when it is needed most. By the year 2026, the IESO plans to have a minimum of 1,217 MW of energy storage in the province.

The IESO also announced in 2023 that it was securing 586 MW of additional capacity by leveraging existing natural gas generation infrastructure. The IESO has taken the position that in order to transition to a fully clean energy system, Ontario will need to continue to use natural gas generation until nuclear and other clean energy technologies generate enough electricity to meet demand.

To maintain the 107 small hydroelectric generating stations in Ontario, the Minister of Energy directed the IESO to develop a **small hydro program** that will modernize existing generating facilities and provide additional generation. The government has also asked its own wholly-owned generation company, Ontario Power Generation Inc. (OPG), to undertake similar projects within its hydroelectric portfolio.

In the most recent milestone in the IESO's current procurements, December 12, 2023 was the submission deadline for the IESO's Long-Term 1 Request for Proposals (LT1 RFP), pursuant to which the IESO anticipates that it will procure 2,518 MW of year-round electricity capacity, of which 1,600 MW is expected to be storage. As with the E-LT RFP and previous IESO procurements, the LT1 contracts are for a 20-year term from the commercial operation dates of the successful projects.

Resource Adequacy Update

The IESO released its **resource adequacy update** (RA Update) on December 11, 2023. The RA Update had welcome news, including a 5,000 MW procurement target for new energy supply beginning in 2029 and growing through the 2030s. With flexible commercial operations dates, the Long-Term Procurement 2 Request for Proposals (LT2 RFP) is expected to solve emerging electricity needs between 2029 and 2031. The IESO is also considering taking a bifurcated approach to the LT2 RFP that separately evaluates long lead time resources under a bespoke procurement target (e.g., 500 MW/2,000 MW).

While the LT RFPs will continue to target non-emitting new-build resources, medium-term (MT) RFPs will be offered in alternate years to incent existing non-emitting sources (primarily wind and solar PV) to remain after their

respective supply contracts expire between 2026 and 2035. The IESO is hopeful that these variable generation sources will become eligible to participate in the pending MT and LT procurements by pairing with the storage capacity recently procured through the E-LT RFP and the LT1 RFP, particularly since standalone storage will be treated as capacity only resources and therefore ineligible to participate in the 2029-2034 energy procurements.

Unlike in the E-LT RFP and LT1 RFP, distributed energy resources will be permitted to participate in the 2029-2034 energy procurements. While future capacity procurements are likely to continue to entail pre-proposal submission deliverability testing requirements, future energy procurements may not require the same degree of congestion management. Increased daily demand shifting to overnight periods — exacerbated in part by increased electric vehicle charging and the introduction of an overnight ultra-low electricity rate — has created a more consistent need for energy as compared to capacity used to meet system peak demand periods. Further, recently procured standalone storage may create more siting flexibility for renewable generation resources thereby easing competition for interconnection availability. Post-proposal submission deliverability evaluation, however, is still expected to be conducted by the IESO.

Though the Ministry intends to provide more certainty to energy project developers and investors, the RA Update rightly notes that the 5 TWh procurement target is a conservative estimate based on a number of variables including:

— the likelihood that newly procured assets are able to enter service as anticipated, in the volumes procured;

— growing pains inherent to new technologies, including their ability to participate and operate effectively in the real-time market and contribute to system needs immediately after entering service;

— the ability for aging assets (including Feed-In Tariff-contracted wind and solar) to continue to contribute to resource adequacy in a consistent manner; and

— government policy and pending legislative considerations inherent to some thermal generation (i.e., natural gas generation).

Finally, the RA Update acknowledges the significant impact that parallel considerations, such as Indigenous community and municipal council support and buy-in, may have on the ability to satisfy the province's growing electricity demand needs. To help mitigate against these risks, the IESO encourages early municipal council engagement and revisiting agricultural and Crown land use restrictions and permitting. The RA Update also reiterates the need to expedite transmission system planning and buildout to support the net new energy producing resources.

Unless these and other related measures are undertaken in co-ordination with the federal and municipal governments, the 5 TWh energy procurement target alone is unlikely to provide project owners and investors with sufficient regulatory certainty to commit to continuing operation of their existing facilities coming off contract or deploying the necessary capital to build new supply resources to meet Ontario's future electricity needs.

POWER PURCHASE AGREEMENTS AND ESG

On November 2, 2023, Ontario issued a **proposal** to amend the **Global Adjustment (GA) regulations** under the *Electricity Act, 1998* which would allow Class A participants under the Industrial Conservation Initiative (ICI) to enter into power purchase agreements (PPAs) with certain types of renewable electricity generation facilities to offset consumption during the 'high five' system peak hours.

Specifically, Class A participants could enter into private supply agreements for qualifying renewable electricity generation and, in turn, reduce the amount of electricity withdrawn from the IESO-controlled grid during the five highest demand peak hours (for as early as the May 1, 2024 to April 30, 2025 base period) upon which Class A participants are assessed their respective GA charges (for the following adjustment period commencing July 1, 2025). Eligible renewable energy generation is currently proposed to include wind, solar, small hydroelectric (i.e., less than 10 MW), biofuel and battery storage.

The proposal would treat separately connected supply under the PPAs as behind-the-meter for GA calculation purposes, effectively creating a regulatory framework for the implementation of virtual net metering in the province. The proposal is intended to incent increased development of new 'clean' electricity generation as well as enhance industrial competitiveness. The proposal does not state whether it will include, or be accompanied by, a contemporaneous regulatory framework to offset the increase in GA charges that Class B customers will be required to pay if the proposal is approved.

Although virtual PPAs are already permitted in Ontario, they have been few and far between due to the inability to hedge against GA charges, which has comprised the majority of electricity commodity costs in recent years. The proposal addresses this regulatory conundrum, which may result in an uptick in corporate PPAs in the province and serve as another mechanism — in addition to the recently implemented **clean energy credit registry** — that Class A customers can use to achieve their environmental, social and governance (ESG) goals.

The proposal comes on the heels of the release of the **federal draft clean electricity regulations**, the latter of which is contingent upon rapid development of large grid-scale non-emitting electricity resources by 2035 in Ontario and across the country. It will be interesting to see if and to what extent the proposal will help achieve Canada's net zero goals.

EXPANSION OF HYDROELECTRIC POWER

Hydroelectric power is a clean, reliable and low-cost renewable energy source that serves as a cornerstone of Ontario's renewable energy sector. In 2020, it accounted for approximately 24% of Ontario's electricity generation capacity. On average, hydroelectric power is the lowest-cost electricity in Ontario. The province has extensive infrastructure with various hydroelectric stations that contribute substantially to its grid. Alongside existing facilities, ongoing initiatives and investments in hydroelectric development projects signify a commitment to further leveraging Ontario's hydrogeneration potential. These efforts not only cater to the current energy demands but also align with the province's sustainable energy goals, reinforcing hydroelectric power as a pivotal component of Ontario's diverse energy mix.

The regulatory and policy framework in Ontario plays a fundamental role in fostering the growth and expansion of hydroelectric power. Government policies and regulations tend to incentivize investment in hydroelectric power. An example of such policies is the feed-in tariff program introduced in 2009 and that offered attractive rates for renewable energy producers, thereby encouraging the development of hydroelectric projects in addition to wind and solar projects. Initiatives such as the Ontario Ministry of Energy's conservation first framework and the government of Ontario's long-term energy plan have outlined strategies to prioritize clean energy sources, including hydroelectric power, in the province's energy mix. Provincial support through streamlined permitting processes, financial incentives and clear guidelines has provided a conducive environment for hydroelectric power expansion, attracting private investments and fostering innovation within the sector.

Ontario's untapped hydro potential remains significant given its expansive network of lakes and rivers. In particular, northern rivers have potential power of about 4,000 MW that could power about 3.5 million homes. The province encourages developers to work with local Indigenous communities in partnership to identify and explore new hydroelectric development opportunities in remote areas.

As noted above, the Minister of Energy has recently provided directives to the IESO and requests to OPG to incentivize additional development of hydroelectric facilities. In one recent project, OPG completed the **redevelopment of Calabogie Generating Station** in early 2023. This hydroelectric station was originally built in 1917 and suffered extensive damages from a tornado in 2018. With two new units, this renewed station has doubled its hydroelectric generation from five to approximately 10.7 MW, which can power about 10,000 homes.

ONTARIO'S IMPLEMENTATION OF ITS LOW-CARBON HYDROGEN STRATEGY

Hydrogen Strategy for Ontario

In addition to the steps the Ontario government has taken to incentivize electricity infrastructure investment, it is also continuing to implement its **Low-Carbon Hydrogen Strategy**, which was presented to the public on April 7, 2022. The **Ministry of Energy** directed the IESO to lead, support and investigate program options that could integrate low-carbon hydrogen technologies into Ontario's electricity grid. After conducting stakeholder engagement and research, on October 31, 2022, the IESO provided the Ministry of Energy with a final report that highlighted the potential roles for hydrogen to benefit Ontario's electricity system, including the use of hydrogen storage and generation to balance more efficiently the supply and

demand on the grid, and potentially blending hydrogen into natural gas-fired turbines for peaking capacity. On January 26, 2023, the Ministry of Energy directed the IESO to develop and implement a Hydrogen Innovation Fund (HIF) that will invest C$15 million over the next three years to investigate and objectively evaluate emerging low-carbon hydrogen projects that can be integrated into Ontario's electricity grid in a reliable, affordable and sustainable manner.

Hydrogen Projects

The HIF covers **three project types**:

1. Hydrogen production from electricity to explore how a hydrogen production facility can provide grid services (e.g., energy, operating reserve, ancillary services), while producing hydrogen for various end uses;
2. Electricity generation from hydrogen, including co-firing hydrogen with natural gas in order to evaluate the impact of hydrogen blending on turbine efficiency and emissions reduction; and
3. Support for the development of the broader hydrogen economy, including exploring the feasibility of site-specific hydrogen conversions at different locations across the province.

In February 2023, the Ontario government invested in **six projects** through the HIF:

1. Enbridge Gas in Markham received C$1,787,480 for North America's first hydrogen driven combined heat and power facility that can also blend hydrogen with natural gas to produce energy.
2. Emerald Energy from Waste Inc. in Brampton received C$2,990,000 for a new facility that will produce hydrogen from waste to test its ability to provide electricity grid services and supply hydrogen to heavy duty vehicles.
3. Carlsun Energy Solutions received C$1,891,400 for a new electrolyzer to test its ability to provide electricity grid services and supply a hydrogen fuelling station in Port Elgin.
4. Carlsun Energy Solutions received an additional C$500,000 for its Goderich and Seaforth locations to study the feasibility of using off-peak electricity to produce hydrogen for power generation and ammonia for fertilizer.
5. Kinectrics received C$250,000 to study the feasibility of integrating hydrogen production, hydrogen power generation and a hydrogen fuelling station.

6. The University of Windsor received C$130,000 to research the potential of low-carbon hydrogen produced with wind to provide grid services and support the greenhouse sector.

In November 2023, the Ontario government invested an additional C$5.9 million in **nine new projects** through the HIF:

1. Atura Power received C$4.1 million to blend hydrogen with natural gas to produce electricity at Halton Hills Generating Station making it the largest electricity-based, grid-connected, low-carbon, hydrogen-blending project in Canada's history. The Niagara Hydrogen Centre will utilize excess water that would otherwise have been spilled over Niagara Falls to create clean electricity that will be used to produce clean hydrogen for the project.
2. Capital Power received C$206,300 to study the feasibility of blending hydrogen with natural gas (between 5-15% hydrogen) at its existing Brampton, Windsor and Newmarket generation facilities.
3. Capital Power received C$150,000 to study the feasibility of producing and storing low-carbon hydrogen — produced from wind generation — to fuel a hybrid hydrogen-methane turbine at its Goderich location.
4. HydroMéga Services in Cochrane received C$100,000 to study the feasibility of upgrading an existing 27 MW natural gas facility to include renewable generation, low-carbon hydrogen production and storage.
5. York University received C$38,000 to study the feasibility of retrofitting existing gas turbine generators to blend hydrogen with natural gas to generate electricity.
6. York University received an additional C$90,000 to model and analyze the potential of installing low-carbon hydrogen facilities across Ontario, including costs and sizing.
7. Western University received C$498,000 to develop a demonstration site, which will test solar-generated hydrogen and biogas-generated hydrogen in order to assess the environmental benefits of each.
8. Volta Energy in Toronto received C$491,352 to assess how reversible solid oxide hydrogen cells technology can help provide a pathway for hydrogen integration into the electricity grid.
9. The Transition Accelerator in Hamilton received C$101,205 to research the economic readiness of the Hamilton region to become a hub for hydrogen investment.

All of these projects are intended to help enable Ontario to further meet electricity demand in the coming years. While it is still unknown how much of a role hydrogen will play in contributing to the provincial electricity grid, these types of projects could benefit future low-carbon initiatives that fit with Ontario's short, medium and long-term energy procurement goals.

QUÉBEC REGIONAL OVERVIEW

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QUÉBEC REGIONAL OVERVIEW

INTRODUCTION

There was robust activity in the power sector in Quebec in 2023, as the Québec government and other key stakeholders continued taking steps towards increasing the supply of renewable energy in the province in anticipation of increased electricity demand and amid continued decreases in electricity surpluses. Request for proposal (RFP) awards and a new RFP round, Québec's 2035 Action Plan, changes to the province's energy regulation legislative framework and a flurry of activity in the battery manufacturing sector marked an active year in the power space in Québec.

BATTERY SUPPLY CHAIN

Battery Sector Strategy

The Québec government's **Strategy for the Development of the Battery Sector (*Stratégie québécoise de développement de la filière batterie*)** aims to leverage the province's abundant mineral resources, clean electricity supply, proximity to the North American auto manufacturing hubs, availability of skilled labour force and research and development capabilities to produce the world's **greenest batteries** in Québec. There are three components to Québec's battery strategy:

1. Exploit and transform Québec's minerals to manufacture battery components, such as anodes and cathodes, to capitalize in a responsible and sustainable way on Québec's wealth mineral resources.

2. Strengthen Québec's position as a global battery supplier, from mineral extraction to the manufacture of key components, namely through the production of electric commercial vehicles by investing in local manufacturing of components of electric vehicles.

3. Advance battery recycling through cutting-edge technology developed in Québec, in order to integrate Québec into a North American battery recycling logistics chain.

In sum, the Québec government's ambition is to develop local capability covering the entirety of the battery supply chain.

With the advent of electric vehicles being hailed as a new industrial revolution comparable to the development of hydroelectricity in Québec in the 1970s, the provincial government views this industry as a golden opportunity for the province to carve out a key place in the North American auto manufacturing supply chain.

Battery and Energy Transition Valley

Certain Québec municipalities have been singled out by the Québec government to become hubs for battery materials and battery manufacturing in North America, namely the cities of Bécancour, Shawinigan, and Trois-Rivières — which form the **Energy Transition Valley**. Of the three municipalities, Bécancour appears to have been at the forefront of this new battery supply chain initiative, with significant projects already in development or having been announced.

On May 29, 2023, Ultium CAM, a limited partnership between General Motors (GM) and POSCO Future M, received C$150 million in funding from the Québec government to develop its own cathode materials **plant** in Bécancour, with production used to manufacture batteries for GM's Ultium battery program (GM aims to **produce** one million electric vehicles a year by 2025).

On August 17, 2023, Ford Motor Company, SK On, and South Korea's EcoProBM **announced** a C$1.2 billion investment for a cathode manufacturing facility in Bécancour. The project has received C$322 million in conditional funding from the government of Canada, via the Strategic Innovation Fund, with the Québec government also providing a partially forgivable loan of C$322 million through Investissement Québec. Energy supply for the project was later confirmed and announced publicly in November 2023.

Other Hubs for Battery Manufacturing in Québec

Other developments were also announced in the Montreal and surrounding areas. Volta Energy Solutions, set to be one of the world's most important copper foil producers, announced on September 5, 2023 its plans to establish a copper foil plant in Granby. Copper foil is a crucial component used in the manufacturing of lithium-ion batteries, and thus a key component of the battery supply chain.

On September 28, 2023, Swedish manufacturer Northvolt AB **announced** that it plans to build a lithium-ion battery gigafactory in the cities of McMasterville and Saint-Basile-le-Grand, near Montreal. The factory, named Northvolt Six, is planned to have an annual battery cell manufacturing capacity of up to 60 GWh, which is enough to power approximately one million electric vehicles per year. Northvolt **is also contemplating** using the plant to manufacture aviation batteries. The project is one of the largest private investments in the province's history and includes cathode and cell manufacturing and recycling. Funding has already been secured with the federal government and Québec government having committed up to C$4.6 billion. The *Caisse de dépôt et de placement*, Québec's pension fund manager, **announced in November 2023** a C$200-million investment in Northvolt AB, in the form of convertible debt.

RENEWABLE ENERGY RFP OPPORTUNITIES

Ongoing RFP Process and New Project Announcements

Hydro-Québec **announced on March 15, 2023** the seven submissions it had retained following the two calls for tenders launched on **December 13, 2021**. Collectively, these submissions totalled 1,303.36 MW of installed capacity required to meet growing demand for electricity in Québec and other markets served by Hydro-Québec. Deliveries of electricity from these submissions are required to start no later than December 1, 2026.

The selected submissions include five **from the 480 MW originally proposed** block of power from renewable sources, totalling 1001.04 MW, and **two from the 300 MW originally proposed block of** wind energy, totalling 302.32 MW of installed capacity. Six of the seven winning submissions are wind energy projects. With respect to Hydro-Québec Production's winning submission, Hydro-Québec **indicated** that it plans on using existing systems and infrastructure to deliver the power awarded to them under the call for tenders. Electricity supply contracts for the projects were signed between Hydro-Québec and the various electricity producers retained in spring of 2023, and were later approved by Québec's *Régie de l'énergie*, the province's energy regulator, in September 2023. However, the producers will need to obtain other authorizations, permits and other regulatory filings for their projects to move forward and construction to start.

Details of New 1,500 MW RFPs Launch

The Québec government and Hydro-Québec had announced on April 20, 2022, as part of the *2030 Plan for a Green Economy*, the launch of two new RFPs for a total block of 2,300 MW of renewable energy. This announcement would have launched the largest renewable energy procurement project in the province's history. However, in early 2023, these RFPs were quietly cancelled. This decision was believed in part to be due to infrastructure and localization challenges encountered during the awarding of the previous RFP's projects. Following a period of internal consultation, the Office of Québec's Minister of Economy, Innovation and Energy and the Minister responsible for Regional Economic Development announced on March 16, 2023 a 1,500 MW block wind energy call for tenders (RFP).

The RFP was launched by Hydro-Québec on March 31, 2023, with submissions filed mid-September of this year. Initial plans for this RFP were to announce the successful bidders by the end of December of 2023, however as of press time no announcement had been made. Successful projects will be required to connect to Hydro-Québec's main transmission network between December 1, 2027 and December 1, 2029. It is anticipated that other renewable energy RFPs may be announced in the coming year.

This RFP featured a novel geographical component, as certain Québec regions **were identified** as strategic areas where infrastructure capacity was available for integration into Hydro-Québec's power grid. Projects submitted to the RFP were required to be located in the target areas, including Saguenay-Lac-Saint-Jean, Rivière-du-Loup, Nicolet, Baie-Comeau, the Montreal area, Salaberry-de-Valleyfield, Montérégie, Des Cantons, and Montmagny.

HYDRO-QUÉBEC ACTION PLAN 2035

Hydro-Québec issued in November 2023 its **2035 Action Plan**. The 2035 Action Plan lays out an ambitious strategy for the transition toward a low-carbon economy and C$100 billion in investments to that end and builds on measures announced in Hydro-Québec's 2022-2026 Strategic Plan, **which included goals** for the province to achieve the capacity to generate approximately 8.2 TWh of energy by 2029 in order to meet the growing demand for electricity in the context of the energy transition, electrification and decarbonization of the Québec economy.

The 2035 Action Plan states Hydro-Québec's clear goal to reduce the environmental impact of generating, distributing and consuming energy in Québec, while leveraging Québec's renewable energy potential to fuel economic growth and development of new projects. Five priorities are set out to guide Hydro-Québec, and three additional objectives have been singled out as essential to fulfilling the 2035 Action Plan: (i) decarbonization by phasing-out fossil fuels in favour of renewable energy; (ii) utilizing cleantech innovation to optimize the energy sector; and (iii) decentralization to educate customers how to manage efficiently their energy use.

An End to Hydro-Québec's Energy Surpluses

Hydro-Québec's significant energy surpluses were a key feature of the last decade, leading to major transactions whereby Hydro-Québec committed to supply clean power to New England and New York and, in doing so, achieving decarbonization goals while generating revenue streams for Québec. Hydro-Québec hopes to derive greater benefits from its exports of power by leveraging the value of ancillary services offered by hydropower electricity generation over other sources of electricity, such as its reserves that can be dispatched quickly and power line frequency control.

The energy abundance in Québec is set to soon come to an end, with the 2035 Action Plan anticipating that peak power needs will match available supply as of 2027. More energy capacity and supply will be needed in order to honour Hydro-Québec's existing commitments, electrify the transport sector and decarbonize buildings and industries by replacing polluting substances and existing heating systems, the whole while supporting the development of new industrial projects and economic growth in the province.

As **discussed below**, a new legislative bill this year lowered the capacity automatically made available by Hydro-Québec to new industrial consumers from 50 MW to 5 MW, with all projects above this threshold requiring discretionary government approval. While the 2035 Action Plan does not specifically address the new legislative framework for capacity allocations, developers and industry observers can take comfort in the fact that the current mismatch between energy supply and demand is expected to be temporary as both Hydro-Québec and the Québec government recognize that decarbonization and economic growth require, larger electricity supply capacity in both the medium and long term.

Expanding Generating Capacities by 2035

Hydro-Québec's plans to integrate new energy resources and new technologies into its transmission network and to invest in existing infrastructure in order to expand its energy generating capacity by 8,000 MW to 9,000 MW by 2035. As **discussed above**, Hydro-Québec has already taken action on that front by launching calls for tenders for wind power to meet those needs.

While no specific plans have been disclosed in the 2035 Action Plan, Hydro-Québec **has publicly considered** the possibility of developing more large-scale hydro power projects, possibly on a scale larger than the Romaine hydroelectric facilities inaugurated earlier this year, and reminiscent of the La Grande (in the James Bay area) and Manic (located in Québec's North-Shore region) projects that form the cornerstone of Hydro-Québec's generating capacity and expertise for decades.

Hydro-Québec is also looking abroad to share its renewable energy expertise while building on global opportunities. To that end, it has entered into a strategic partnership with Innergex to develop power generation projects internationally. The initiatives outlined in the 2035 Action Plan are expected to not only create opportunities for private electricity producers, but also for equipment manufacturers, construction companies and various expertise providers in the field of power generation and distribution.

Plans and Programs for Companies

Plans to expand generating capacity by 2035 are expected to come with additional capital costs. This in turn could potentially generate extra pressure on the costs of electricity in Québec, in order to fund the various electricity production projects.

As a result, Hydro-Québec has indicated it wishes to create programs to assist companies in navigating the energy transition by providing help and resources to make better energy consumption choices and to incorporate

energy-efficient equipment into their business. The 2035 Action Plan suggests that corporate customers could be compensated if they put in place electricity efficiency measures resulting in decreased electricity usage during peak periods such as during cold winter nights.

Overall, the 2035 Action Plan provides a path to address the current challenges of electricity supply in the province. In addition, the C$100 billion in expected investments by 2035 show both Hydro-Québec's and the Québec government's commitment to support the energy transition and economic growth both in Québec and abroad, while creating an array of business opportunities for stakeholders of all kinds.

BILL 2 – LIMITS TO PRIVATE POWER SUPPLY POSSIBILITIES

The *Act mainly to cap the indexation rate for Hydro-Québec domestic distribution rate prices and to further regulate the obligation to distribute electricity* (*Bill 2*), received assent on February 16, 2023. Bill 2 amends the *Act respecting the Régie de l'énergie* to give the Québec government the power to determine by regulation the cases in and conditions on which Hydro-Québec does not have the obligation to distribute electricity. The transitional provisions of Bill 2 provides that until such regulations are adopted, the obligation to distribute electricity will not apply to any request that: is new, is for additional supply, or is from a client benefiting from a special agreement and is for a power supply of 5,000 KW (5 MW) or more.

These legislative amendments introduced a new power allocation system for energy-intensive projects, which grants the Québec government greater control in the approval of power supply. Under the new framework, any project with a power demand of more than 5 MW now requires the approval of the Minister of Economy, Innovation and Energy, whereas previously Hydro-Québec had the obligation to supply power to projects with power demand of less than 50 MWs. In assessing the power supply requests, the following criteria will be taken into account: Hydro-Québec's technical capabilities to allow for connection to the proposed project, as well as the economic benefits and social and environmental impacts of how the energy would be used. Additional **selection criteria published** by the Québec government include support for regional development and consistency with the government's other policies and strategies, including with regard to the green economy, critical and strategic minerals, batteries, hydrogen and aluminum.

On November 10, 2023, the government announced **11 projects** selected in August 2023, for a total of 956 MW required power supply, including five projects relating to the battery sector, two bioenergy projects, one hydrogen project, one data centre, one manufacturing project and one green steel project.

In January 2024, **news sources reported** that the Quebec government was **planning a significant shift in its electricity market regulations** and would introduce a bill altering Hydro-Québec's longstanding monopoly on electricity distribution. The proposed change would authorize direct electricity sales between private parties by expanding the existing right to self-produce renewable electricity to include sales to customers in proximity of the production site. The reform could be one of the most consequential changes to Quebec's energy regime since the nationalization of electricity in 1962, and we will be following it closely.

CONSULTATIONS ON FRAMEWORK AND DEVELOPMENT OF CLEAN ENERGY IN QUÉBEC

The Québec government announced its intention to submit before the national assembly a bill to modernize the legal and regulatory framework of Québec's energy sector. The bill would amend the ***Hydro-Québec Act*** and the ***Act respecting the Régie de l'énergie*** and the regulations enacted under those acts. The purpose of the amendments would be to align the legislation with the province's commitment to decarbonize its economy by 2050, meet environmental and social standards and generate economic opportunity for the citizens of Québec. In order to achieve its objectives, the Québec government plans to prioritize electrification, energy efficiency and other renewable energy sources such as bioenergy. The bill was initially expected to be introduced by the Québec government in the fall 2023 but has yet to be introduced. It is expected that it will be tabled in early 2024.

Consultations in preparation for this new bill took place initially on May 15, with experts taking part in different workshops. Consultations were later expanded from June 2 to August 1, during which time all citizens were invited to take part in an **online consultation hosted on the Québec government's web platform**. Representatives of First Nation communities were also consulted on September 18, 2023. In order to assist the stakeholders with preparing briefs to be submitted to the consultation, the Québec government made available the ***Guide du participant***. Citizens and organizations were invited to comment, among others, on the following topics:

1. **Supply-demand balance:** The opportunity to recourse to a wider range of options and models to meet supply

demand (including the modulation of distribution exclusivity, self-production and microgrids), to simplify the process of domestic supply and its framework and to improve energy security and reliability;

2. **Pricing:** The opportunity to adjust the process of setting electricity and natural gas rates, to better align the pricing process with the cost of services and to make upstream investments in infrastructure; and

3. **Governance:** The opportunity to adjust the legal and regulatory framework (particularly with regard to the roles, functions and powers of the regulator, the government and energy carriers and distributors) and to benefit from integrated energy resource planning.

In total, 119 briefs were submitted by citizens and organizations to the Québec government for its consideration as it determines the best options for the energy transition and the development of clean energy.

Interested stakeholders (ourselves included) will now have to wait for the tabling of the draft bill to assess whether the proposed modernization of the legal and regulatory framework of the energy sector will address the challenges of the energy transition.

OTHER TRENDS

Community Partnerships

A key outcome of Hydro-Québec past and current strategic and action plans has been increasing involvement of local stakeholders — such as municipalities, First Nations and the Inuit Nation — in the development of new generation and transmission projects.

For many years, regional municipal actors have been involved at the outset of calls for tenders for wind energy projects to ensure local adhesion, with many taking minority ownership stakes in projects. Most of Hydro-Québec's new initiatives involve collaboration with First Nations and the Inuit, which are a priority for the government-owned corporation. First Nations and the Inuit are expected to take operations and ownership interests in certain new generation projects.

Recent Hydro-Québec electricity production projects have also sought to bring renewable electricity to remote communities such as Inuvik, in the Nunavik region of Québec. On the electricity transmission side, Hydro-Québec has continued its partnership with the Mohawk Council of Kahnawake through a joint venture to build and operate the Québec portion of the Hertel-New York Interconnection line.

The new projects will involve job offers and skill-building opportunities to adapt the projects to the needs of First Nations. This creates an opportunity for companies to expand their activities in regions where the workers are more difficult to find.

Municipal and Land Planning Changes to Accelerate Wind Energy Projects

In connection with the enactment of its amendments to the *Act respecting land use planning and development*, the Québec government launched a public consultation to update its *Orientations gouvernementales en aménagement du territoire* (OGAT), which took place over spring and summer of 2023. OGAT are central and binding guidelines that the government expects to see reflected in land use planning regulation. The general OGAT had last been updated in 1994 and 1995, although some topic specific OGAT were enacted since then. The new OGATs are expected to formally integrate the 2007 government orientation document on wind farms, **Pour un développement durable de l'énergie éolienne**, as the 9th preliminary guideline.

The announcement for the official OGAT and the government's priorities is expected for Spring of 2024. Should the wind farm content remain the same as the one announced during public consultations, all Québec regional authorities, such as municipal regional counties, would be required to update their master planning documents, the "RCM plan," to include measures allowing for sustainable wind farm development in compliance with these guidelines. This would eventually be reflected in changes to local "zoning" regulations enacted by various municipalities. While it may take years for these changes to be enacted locally, this process could have the potential to accelerate project development and to clarify existing regulation.

ATLANTIC PROVINCES REGIONAL OVERVIEW

Authors: Elena Sophie Drouin, Stephen Furlan, Lynn Parsons Jacob Stone and Gaëtan Thomas

ATLANTIC PROVINCES REGIONAL OVERVIEW

Atlantic Canada's power sector experienced a year of continued growth and activity in 2023. The region's provinces (Nova Scotia, Newfoundland and Labrador, New Brunswick and Prince Edward Island) all made headway on their plans to transition to new and renewable energy sources. This shift has led to further opportunities for public and private projects aimed at increasing the supply of energy in the region.

OFFSHORE, MARINE AND TIDAL POWER AMBITIONS

Marine and tidal power development continued in the Atlantic region, particularly in Nova Scotia. The offshore wind potential in the Atlantic region is thought to be stronger than that of the more developed region of Northern Europe and offers greater wind speeds than those available in the northeast coast of the United States.

The Canadian government revealed plans to regulate offshore wind energy projects in Atlantic Canada. The existing offshore accords with Nova Scotia and Newfoundland and Labrador are being updated to facilitate the development of offshore wind farms. This announcement followed an assessment of offshore wind development by the federal government that had begun in 2022 under the *Impact Assessment Act* in the Atlantic region (**Newfoundland and Labrador** and **Nova Scotia**) which are still ongoing, and the publication of draft agreements between the federal government and each of **Nova Scotia** and **Newfoundland and Labrador** in fall 2022.

On May 30, 2023 then Minister of Natural Resources of Canada, Jonathan Wilkinson, introduced legislation to allow offshore wind energy development for the first time in Atlantic Canada. Bill C-49, ***An Act to amend the Canada–Newfoundland and Labrador Atlantic Accord Implementation Act and the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act and to make consequential amendments to other Acts*** (Bill C-49) amends the ***Canada–Newfoundland and Labrador Atlantic Accord Implementation Act*** and the ***Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*** (Atlantic Accords Acts). The Atlantic Accords Acts implement agreements between Canada and the two provinces on the joint management of offshore petroleum resources but did not previously provide for regulatory approvals of offshore wind energy projects. Bill C-49 modernizes the Atlantic Accord Acts by notably establishing a framework for the development and regulation of offshore renewable energy projects in both Nova Scotia and Newfoundland and Labrador and their offshore areas. Bill C-49 also expands regulation of current petroleum projects and clarifies jurisdictional rules regarding domestic and internal sea boundaries.

The expansive amendments introduced by Bill C-49 are expected to streamline applications for seabed rights approvals by introducing a single "submerged land" licence to carry out offshore renewable energy projects. This system would replace the existing tenure system where multiple licences are issued in the context of petroleum project development.

Regulatory authority for offshore wind power would be granted to the two existing jointly managed offshore boards that are currently exclusively responsible for regulating offshore oil and gas projects: the **Canada-Nova Scotia Offshore Petroleum Board** and the **Canada-Newfoundland and Labrador Offshore Petroleum Board**. They will be renamed the Canada-Nova Scotia Offshore Energy Regulator and the Canada-Newfoundland and Labrador Offshore Energy Regulator (Regulators). The Regulators would have the power to govern various aspects of offshore renewable energy activities, such as safety, environmental protection, decommissioning and royalties. The Regulators would also have the authority to conduct environmental assessments, public hearings, and dispute resolution processes related to offshore renewable energy projects.

Bill C-49 also proposes amendments to the existing regulation of offshore petroleum activities to align them with the new provisions on offshore renewable energy and includes a series of broader changes to environmental, jurisdictional and enforcement aspects of the existing legislation. Key changes to the management rules for transboundary offshore pools and fields are expected to ensure consistency and co-operation among the relevant jurisdictions.

From an environmental perspective, Bill C-49 would have **Marine Protected Areas** standards apply to all offshore areas governed by the regulations, meaning that offshore wind farms should be permitted within these Marine Protected Areas. The new federal impact assessment process will be applicable to offshore energy development. For petroleum projects, future significant discovery licences will be limited to 25 years, replacing the indefinite term currently in place. Existing significant discovery licences, however, would remain exempt from the 25-year limit.

Bill C-49 was before the House of Commons committee, as of October 17, 2023. Both the Newfoundland and Labrador and the Nova Scotia governments are expected to introduce similar legislation to complete the framework proposed in Bill C-49. As a result, Newfoundland and Labrador Premier Andrew Furey **signed in December** a memorandum of understanding (MOU) with the federal government allowing the province to develop offshore wind farms by identifying 16 bays as being of exclusive provincial jurisdiction. This enables the province to develop wind farms as though they were on provincial land. The MOU will enter into effect once Bill C-49 has been enacted.

HYDROGEN TRENDS

Hydrogen is recognized as a vital component in Canada's strategy to achieve its net-zero goals and the federal government has strategic plans for Canada to become a leading supplier in a net-zero emissions world. Building on the ***Hydrogen Strategy for Canada***, unveiled in December 2020, the 2023 Budget introduced a Clean Hydrogen Investment Tax Credit, which offers tax support ranging from 15% to 40% of eligible project costs, with the highest support levels going to projects that produce the lowest carbon-intensity hydrogen, which will help sustain regional interest in developing a budding Atlantic hydrogen sector. (See Clean Hydrogen Investment Tax Credit below.)

The government of Newfoundland and Labrador aims to establish the province as a major hydrogen-producing and exporting hub. Hydrogen project development is particularly focused on European markets, with countries like Germany identified as potential major purchasers of hydrogen. Following the 2022 ***Joint declaration of intent between the Government of Canada and the Government of the Federal Republic of Germany on establishing a Canada-Germany Hydrogen Alliance***, work has continued to enable the start of Canadian shipments of hydrogen to Germany as early **as 2025**, with further plans to develop a transatlantic hydrogen supply chain by **2030**. In November 2023, Prime Minister Justin Trudeau **hosted** top European Union leaders in St. John's for a Canada-EU Leaders' Summit, which included discussions on climate change and hydrogen.

The government's commitment to hydrogen energy development was made evident by significant investments, including tax credits and funding for the port of Argentia expansion, which is necessary for the production and export of hydrogen. This initiative is part of a broader C$4-billion project by Pattern Energy, which **signed** an option to lease up to 6,000 acres of undeveloped land for its port of Argentia green hydrogen project. The project is multi-dimensional in nature, with the initial phase **involving** 300 MW of installed wind power and a hydrogen electrolysis plant with a storage facility and other fuel infrastructure.

Newfoundland and Labrador's government **is currently evaluating four wind hydrogen proposals** located on public land. ABO Wind plans to develop green hydrogen and ammonia in partnership with Braya Renewable Fuels and the Miawpukek First Nation, through the **Toqlukufi'k Wind and Hydrogen Project** located in the vicinity of the Avalon Isthmus. The project would supply the Braya Come By Chance Refinery with 5,000 MW of wind power, in three phases scheduled to start in 2025 and end in 2034.

The **Exploits Valley Renewable Energy Corporation** is another multi-phase wind-hydrogen project that plans to export green hydrogen and ammonia from Botwood in Central Newfoundland, while also expanding existing regional infrastructure. The company **signed** a memorandum of understanding with Qalipu Holdings LP on behalf of the Qalipu First Nation in connection with the project, and there are plans to negotiate an impact benefits agreement.

A joint wind farm/hydrogen project has been proposed by World Energy GH2, and it plans to build 164 wind turbines in Port au Port Peninsula and the Anguille Mountains in western Newfoundland to produce approximately 500 MW of energy. Part of the project would involve **building** an ammonia plant in Stephenville to generate green hydrogen.

EverWind Fuels **was also awarded** the right to pursue the development of a green fuel project on the Burin Peninsula in Newfoundland and Labrador, following a successful bid for Crown land. The project is expected to be generating power by 2027, while construction may begin in 2024. The Burin Peninsula project could generate at least 2 GW of wind energy, some of which would potentially be produced by offshore wind farms.

EverWind Fuels has also been very active in Nova Scotia and **has received** government approval for a green hydrogen and ammonia production and storage project in Point Tupper and Strait of Canso area of Nova Scotia (EverWind NS Project). A partnership with **Membertou, Bear Lake and Kmtnuk** First Nations, the project involves multiple phases and aims to **start** producing green ammonia in 2025, with production expanding to one million tonnes of green ammonia by 2026, using **wind and solar energy sources**. EverWind Fuels has **announced** the development of three wind farms to power the EverWind NS Project for a total of 530 MW. **Canada announced** its support for the EverWind NS Project on November 17, 2023 through an agreement in principle for a C$125-million debt facility provided by Export Development Canada on behalf of the government of Canada.

In addition to EverWind NS Project, another green hydrogen export project to be located in the Point Tupper region is being proposed near Bear Head, Nova Scotia and **received approval** from the province's environment minister. The proponent for this project, **Bear Head Energy,** plans to invest in Nova Scotia's power grid to transport electricity from its wind farms to its Point Tupper facility.

Nova Scotia released on December 15, 2023 its ***Green Hydrogen Action Plan***, which outlines seven goals and 23 action items to support the green hydrogen industry as a viable alternative to fossil fuels. As with Newfoundland and

Labrador, the initial focus for the green hydrogen industry in Nova Scotia is on European exports, with the goal of eventually developing a domestic market.

ATLANTIC LOOP ON PAUSE

The Atlantic Loop project was meant to provide significant supply increases and transmission infrastructure upgrades to the Atlantic provinces' power grids, with the view to increasing the load and balancing capacity and bringing in larger volumes of electricity produced in Québec. It was part of the **Clean Power Roadmap for Atlantic Canada**, released by the government of Canada and the Atlantic provincial governments in March 2022.

Amid soaring costs, which have tripled to more than C$9 billion from initial projections, dwindling supply prospects from Quebec due that province's own projected reduced electricity surpluses and other logistical complexities associated with the Atlantic Loop, Nova Scotia **announced** on October 11, 2023 that it would instead redirect its focus toward the development of wind and solar energy to meet its 2030 renewable energy targets. Improved interprovincial connectivity still remains a priority, however, as Nova Scotia has indicated that it will increase its focus on imports of hydroelectricity from Labrador and plans to improve transmission line infrastructure with New Brunswick (see discussions below on Nova Scotia's 2030 Clean Power Plan).

OTHER NOVA SCOTIA UPDATES

Snapshot of Nova Scotia's Bold Vision for a Clean Energy Future by 2030

Nova Scotia's 2030 Clean Power Plan (the 2030 Clean Plan), driven by federal mandates for phasing out coal powered generation facilities and new ***Clean Electricity Regulations***, was released in August 2023. The 2030 Clean Plan's central focus is on affordability, aiming to ensure that ratepayers are protected as much as possible from excessive cost increases.

Nova Scotia **pledged to phase out coal** and achieve a target of sourcing 80% of its electricity from renewable sources by 2030. It is now seeking to reduce greenhouse gas emissions (GHG) from electricity by over 90% from 2005 levels and cut Nova Scotia's total GHGs by more than 53%. Additionally, the province plans to significantly reduce Nova Scotians' expenditure on imported fossil fuels through the electrification of energy consumption.

The 2030 Clean Plan identifies key areas for development including:

- increasing wind, solar and hydropower generation;
- integrating batteries and renewables into its electricity system,
- favouring electrification and load management;
- improving transmission and grid resiliency; and
- planning for fast-acting power generation with oil and gas being used only for emergencies.

The plan includes the following notable highlights:

- Nova Scotia's aim is to increase onshore wind power to account for 50% of its electricity production. The 2030 Clean Plan underscores the potential of Nova Scotia's own energy resources, notably some of the world's most exceptional winds, creating a significant opportunity for wind energy.
- Solar energy, although a smaller component, is also set to see a notable increase in attention. The solar industry is growing rapidly, with employment numbers

expected to double in the next year. The 2030 Clean Plan expects at least 300 MW of larger scale solar will be installed by 2030.

— Between 300 MW and 400 MW of battery storage will be deployed by 2030. The 2030 Clean Plan also focuses on expanding onshore wind generation and solar energy. Harnessing these resources is expected to reduce dependency on imported coal or natural gas, improving energy security and reducing costs. Plans also include investments in fast-acting, dispatchable generation to ensure power during winter peaks or in the event of storms.

Nova Scotia's electricity system's vulnerability to climate change-linked events was underscored by recent incidents such as forest fires, major storms and flooding, each of which have had a significant impact on the province. Such occurrences are not expected to decrease in frequency or intensity. The 2030 Clean Plan aims to build resilience in the face of these challenges into the province's energy system. Moreover, the province plans to enhance its connection to the North American grid through New Brunswick — boosting reliability and network strength with a new transmission line expected to be online by 2028.

LEGISLATIVE UPDATES

Amendments to the Electricity Act

The Nova Scotia government **has introduced amendments** to the *Electricity Act* aimed at increasing the use of renewable energy and facilitating energy storage solutions. Both bills have received royal assent.

Certain amendments to the *Electricity Act* **were announced on March 22, 2023** which are primarily focused on accelerating the adoption of battery storage technologies. Key changes include enabling the government to issue: (i) requests for proposals for energy storage solutions like large-scale batteries, which were previously restricted to ownership by Nova Scotia Power Inc. (NSPI); and (ii) contracts for well-developed and innovative energy storage projects that can be swiftly implemented.

Later amendments were announced on October 13, 2023 that focus on two key areas: (i) enabling the rapid approval of innovative energy storage projects; and (ii) clarifying the process for power purchase agreements. These amendments relate to energy storage and will allow the government to swiftly approve energy storage projects proposed by NSPI. This initiative is particularly significant as it will utilize federal funding to lower costs for ratepayers. One of the primary objectives of these amendments is to promote the use of batteries for storing excess renewable energy, which can be used during peak demand hours. This will reduce waste of renewable energy and enhance grid stability.

The amendments related to power purchase agreements bring clarity to the purchase process, which will enable large-scale electricity customers to buy renewable energy directly from producers at a fixed price, with NSPI managing the sale and delivery. The changes explicitly grant the Minister of Natural Resources and Renewables the authority to direct NSPI to engage in such agreements.

Amendments to the Public Utilities Act

On March 22, 2023, the Nova Scotia government **introduced amendments** to the *Public Utilities Act* aimed at increasing NSPI's accountability, particularly in terms of service delivery and power outage management, with the intention of linking its profits to its performance standards. A significant change introduced by these amendments is the substantial increase per year in the total amount of administrative penalties that can be imposed on NSPI from C$1 million to C$25 million for failing to meet certain regulated targets. Importantly, any fines imposed must be paid from NSPI's profits, ensuring that ratepayers are not burdened.

In addition to increasing fines, the amendments also introduced a new fund, financed in part by these penalties, to compensate customers most affected by power outages. The specifics of this fund, including its management and regulation, are to be detailed in future regulations, which will also establish new performance standards and penalties. The size of penalties may either be specified in these regulations or determined by the Utility and Review Board (UARB).

Subsequent to the introduction of these amendments, NSPI **has been fined** C$10 million for missing its renewable electricity targets. NSPI was supposed to generate 40% of its electricity from renewable sources by 2020, but the deadline was pushed back to 2022. NSPI intends to appeal the fine to the UARB.

Clean Energy Solutions Task Force and Changes to Environmental Legislation

Nova Scotia has **established** a Clean Electricity Solutions Task Force, an expert group focused on modernizing the province's electricity infrastructure and regulatory environment to accommodate an expected influx of clean energy. The task force's key objectives include examining the electricity infrastructure's needs for reliability, capacity and storage, assessing connections to other essential

services like telecommunications, and reviewing the Nova Scotia *Utility and Review Board Act* concerning electricity generation, transmission and rates. The task force is also mandated to engage with subject matter experts, the Mi'kmaq and other interested Nova Scotians. Chaired by Alison Scott, a former energy regulator and deputy minister, and including John MacIsaac, a former utility executive, the task force is expected to submit a final report with recommendations in early 2024.

Other recent regulatory changes were aimed at providing clear and straightforward guidelines for environmental regulations and the green hydrogen sector and included amendments to the *Environmental Assessment Regulations and Activities Designation Regulations*. Key changes include the requirement for large-scale projects that produce and/or store hydrogen or ammonia to undergo a Class I environmental assessment. Additionally, facilities involved in the production and/or storage of these substances will need operational approvals. To reduce administrative burdens, the regulations now allow for several operational approvals to be bundled under a single facility-level approval for hydrogen facilities.

The government of Nova Scotia **has taken steps** to enact by 2024 a significant update of its environmental assessment legislation — which was last revised in 2008 — in order to align it with the *Environmental Goals and Climate Change Reduction Act*. The updated process is expected to incorporate key concepts such as cumulative impacts, diversity, equity and inclusion, independent review, climate change and Netukulimk — the Mi'kmaq concept of sustainable living through respectful cohabitation with the land. Nova Scotians, including Mi'kmaq organizations, businesses and industry representatives, were invited to provide feedback on the proposed amendments. The survey for public feedback closed on October 6, 2023. The government is currently reviewing feedback to inform changes.

New Nova Scotia RFPs and Power Purchase Agreement

In August 2023, the Nova Scotia government **introduced** the Green Choice Program, a novel initiative allowing large-scale electricity consumers to source up to 100% of their power from renewable energy. This program is the first of its kind in Canada and aims to add 10% more renewable electricity to the grid. It targets public institutions, Mi'kmaw band councils, schools, universities, health-care facilities, non-profit organizations and some large commercial or industrial entities. The program opened for applications by interested customers on December 15, 2023, with applications to close on March 4, 2024. Ministerial decisions are expected for May 8, 2024, and agreements between NSPI and participants to be executed in June 2024.

To support this program, Nova Scotia is seeking new renewable energy projects and a **procurement process** was started December 1, 2023 to secure 350 MW of renewable electricity from wind and solar projects. It is expected to be operational by 2027-2028. The procurement is managed independently by Coho Climate Advisors, which also facilitated the province's previous 2021 renewable energy RFP and it bears many resemblances to that program. Participants' notice of intent to bid on the RFP must be provided by April 2, 2024, and project proposals **are due by June 14, 2024**. RFP awards are expected to be announced on September 6, 2024.

Offshore Wind Energy

While Bill C-49 has yet to be adopted, Nova Scotia has set a target of issuing **five gigawatts of licences for offshore wind by 2030** under the *Marine Renewable-Energy Act*. With 20% of this supply expected to come from locations on provincial waters, the government has also **stated its aim** to encourage green hydrogen production. Leasing under this scheme is expected to commence as of 2025.

However, the province has indicated that it will wait for the joint regulatory framework, discussed above at **Atlantic Provinces Regional Overview — Offshore, Marine and Tidal Power Ambitions**, to be established.

In that vein, the Nova Scotia government released **on June 14, 2023**, **Module 1** of the **Nova Scotia Offshore Wind Roadmap**, which details the province's vision for the offshore wind industry, regulation and investment possibilities. This module outlines remaining work required to complete the legislative and regulatory regime for offshore wind projects. Module 2 **will be released** in the spring of 2024 and will focus on developing one clear regulatory regime for federal and provincial jointly managed waters.

While there are no offshore wind projects currently under development in Nova Scotia, **Nova East Wind Inc.**, a joint venture partnership, **announced in August 2023** an offshore wind project in Halifax that aims to install 20 to 25 floating wind turbines off the coast of Goldboro, Nova Scotia. This initiative, spearheaded by SBM Offshore and DP Energy, seeks to supply up to 400 MW of electricity to the province's grid by the end of 2029, which would account for approximately 20% of NSPI's current capacity. The project, estimated to cost between C$1 billion and C$1.5 billion, would see electricity transmitted via undersea cables following along a defunct offshore gas pipeline route. Nova East has already initiated survey work and emphasized the need for early action to meet the 2030 deadline. The company has expressed commitment to working with local communities and First Nations for compensation, especially for fishermen potentially impacted by the wind farm.

NEWFOUNDLAND AND LABRADOR UPDATES

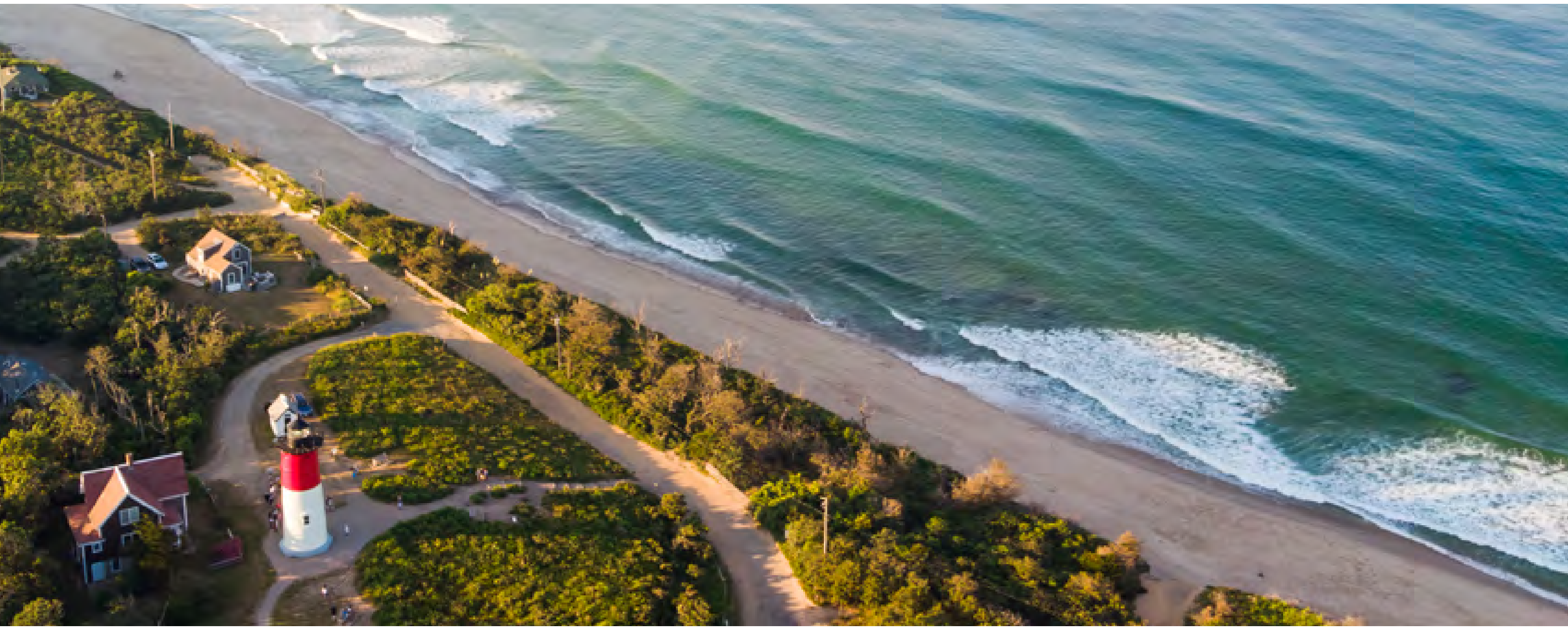
A "Green" Vision

Newfoundland and Labrador continues to make strides in the development and use of renewable energy, particularly wind power and hydrogen. The province is seeking to position itself as a leader in green energy with a special focus on being a **first mover in hydrogen**. Central to its renewable energy strategy are investments in wind-powered hydrogen projects.

Wind energy continues to be an increasingly active sector in Newfoundland and Labrador, spurred by the interest in green hydrogen. As discussed above, companies like Exploits Valley Renewable Energy Corporation, EverWind Fuels, Toqlukufi'k Wind and Hydrogen (ABO Wind), and World Energy GH2 (discussed above in **Atlantic Provinces Regional Overview — Hydrogen Trends**) are spearheading initiatives to harness the province's wind resources for green hydrogen production.

Newfoundland and Labrador Hydro is also planning to add an eighth 150 MW turbine at the Bay d'Espoir hydroelectric dam. The proposed project would involve investment of C$522 million. An application for this upgrade is planned to be filed in 2023 before the Newfoundland and Labrador Public Utilities Board (PUB) and if approved, the project could be in service within **five to eight years**.

Discussions between Newfoundland and Labrador and Québec are also underway for a new Churchill Falls Generating Station electricity deal. Québec Premier François Legault wants to extend the current Churchill Falls



deal beyond 2041 and also sign a new agreement for a proposed dam at Gull Island, Labrador. He has suggested offering financial compensation to Newfoundland and Labrador before 2041 in order to reopen the contract. Premier Furey had indicated that the province is open to discussions that will include talks for expansion at Churchill Falls, which could increase capacity to 1,600 MW and the upgrading of existing turbines.

Traditional Energy Sources

While certain fossil-fuel sourced energy plant projects, such as a proposed diesel plant in Port Hope-Simpson, have been put on hold or set for decommissioning, the province remains committed to the oil and gas industry and hopes to **double** offshore oil production by 2030. The province **opened** calls for **exploration bids** on 28 parcels in its eastern region and 10 parcels in the southeast coastal area. Meanwhile, plans to develop the Bay du Nord oil project **were put on hold by Equinor**, but **the province is still engaging with the company**.

N.L. Hydro has **proposed** building a new diesel-powered combustion turbine on the Avalon Peninsula. The new power plant could produce nearly as much electricity as the 490 MW Holyrood Thermal Generating Station, which is slated for closure in 2030. NL Hydro is currently conducting a study to analyze fuel requirements and site suitability and provide updated cost estimates and a schedule for three capacity options. No decision has been made to move forward with the project yet, but an application to the PUB is expected in the final quarter of 2024 at the earliest, and the project is anticipated to take seven years for approval, construction, and commissioning.

Newfoundland and Labrador also launched a C$100-million Green Transition Fund to help reduce greenhouse gas emissions, financed by the West White Rose offshore oil expansion project, a joint venture among Cenovus Energy Inc., Suncor Energy Inc., and Nalcor Energy. The White Rose offshore field produces about 26,000 barrels of oil per day, but the expansion project will add about 75,000 barrels per day to production. The project is expected to be completed in 2025, with first oil expected in 2026. The fund itself is open to a wide range of projects, with the goal of supporting the province's transition to a green economy.

NEW BRUNSWICK UPDATE

In partnership with the federal government and Nova Scotia, **New Brunswick has signed an agreement** committing to phasing out coal and creating a green energy grid by 2030. The two provinces are pursuing a pared-back version of the Atlantic Loop project (see **Atlantic Provinces Regional Overview — Atlantic Loop on Pause**) that will focus on renewable energy generated within each of their provincial borders, including wind, solar and nuclear, especially in the burgeoning field of small modular nuclear reactors.

ARC Clean Technology (ARC), Korea Hydro and Nuclear Power Co., Ltd., and NB Power signed on November 28, 2023 a memorandum of understanding (MOU) to explore collaboration on the global deployment of ARC's advanced small modular reactor SMR) technology. The MOU contemplates combining expertise in the design, construction, project management, commissioning, operation and maintenance of ARC's advanced SMR in multiple countries. The move follows ARC and NB Power's ongoing work on the ARC-100, a sodium-cooled fast reactor, which is expected to be Canada's first on-grid advanced SMR facility.

The federal government has announced initial funding for the two provinces, including C$11.5 million for Nova Scotia to improve monitoring and automation of its electrical grid, C$7 million to support pre-development work for the proposed ARC-100 small nuclear reactor at Point Lepreau, N.B., C$2 million to explore converting New Brunswick's last coal-fired power plant in Belledune to a "sustainably sourced" biomass facility and C$1 million for the port in Belledune to study establishing a green industrial hub.

NB Power **also released** on June 8, 2023 its "Energizing Our Future" strategic plan, which outlines six objectives. It wants to: (i) better meet customer expectations; (ii) improve its financial position; (iii) create a thriving workforce; (iv) modernize the New Brunswick grid; (v) transition to a cost-effective clean energy supply; and (vi) facilitate electrification by 2035.

To achieve these goals, NB Power will invest in renewable and clean energy solutions, including hydroelectricity, wind and solar energy, and it is pursuing small modular reactors as a potential carbon-free energy source. The utility also aims to decarbonize its infrastructure by 2035, with plans to phase out coal use at the Belledune Generating Station by 2030. The utility will seek regulatory reforms to allow for new ways of serving customers and remaining financially viable, while implementing its plans.

On December 13, 2023 the province of New Brunswick released its ***Energy Strategy – Powering our Economy and the World with Clean Energy – Our Path Forward to 2035***. This strategy sets out the province's 12-year road map to meet national and international clean energy transition targets. It plans to meet its objectives by:

— leveraging existing assets, including the development of hydrogen and other clean energy sources, such as transforming Belledune Generating Station to biomass,

and improving battery storage and adding 1,400 MW of new wind power, 200 MW of grid scale solar power, and 300 MW of behind the meter solar;

- deploying of SMRs, including adding 600 MW of small modular reactors at the Point Lepreau Nuclear Generating Station by 2035;
- creating new clean energy supply chains by transitioning from natural gas to using hydrogen, renewable natural gas, and biofuels;
- fostering economic partnerships with First Nations communities;
- striving toward energy security and net-zero emissions by 2050 by undertaking transmission upgrades and enhancing connectivity within Atlantic Canada; and
- increasing electrification and energy conservation by adding electric vehicle (EV) charging stations and increasing use of biofuels and hydrogen.

P.E.I. GOVERNMENTAL UPDATES

Prince Edward Island's path to renewable energy and to achieving net-zero emissions by 2040 has continued to focus on local self-reliance, wind power and innovative solutions.

The P.E.I. government has sought input on the future of energy on the island, with the **PEI Energy Blueprint,** which is meant to jump-start public consultations. The blueprint proposes a new balance of on- and off-island energy supply, drawing energy from wind, solar and biofuels. The blueprint also calls for a continued switch to electric heating in buildings and growth in electric vehicle use. P.E.I.'s grid will need to be modernized to handle the planned increased load.

Various programs and initiatives that P.E.I. is using in its undertaking to reduce emissions include residential retrofits and fuel switching programs, a rooftop solar program and a path to net zero for the agriculture sector. P.E.I. is also looking into different ways to generate and store energy, including wind farms and small nuclear reactors. Homeowners are also requesting a **change in provincial regulations** to allow them to have backup battery storage in their homes, but the government has indicated it is waiting for national changes to the electrical code, which are expected in spring 2024, before it will move forward.

The federal government **is also investing** almost C$50 million in green energy initiatives in the province. Of that, C$16.8 million will go toward helping low-income homeowners transition from home heating oil to more affordable, low-emitting heating technologies. A further C$31.9 million will go toward provincial initiatives that support Canada's 2030 greenhouse gas emissions reduction target and align with the goal of net-zero emissions by 2050. The federal government is working with the province to finalize an agreement on the delivery of this funding.

Further energy infrastructure projects are anticipated for 2023, in addition to **continuing** repair and reconstruction of existing power generation projects and implementing climate change resilience efforts. A new hydroelectric project **led by Aslan Renewable** plans on using small turbines to power up decommissioned dams in P.E.I. Aslan Renewables has signed a power purchase agreement with the P.E.I. government. The pilot project will include three dams and could supply more than 350 MW hours per year.

ENVIRONMENTAL LAW UPDATE

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KEY DEVELOPMENTS IN 2023

In 2023, there were a number of key environmental law developments across Canada with potential impacts on the power sector. Highlights include the following:

BRITISH COLUMBIA

— **Third annual Climate Change Accountability Report shows progress toward climate goals:** The 2023 Climate Change Accountability Report, which is required to be published under the ***Climate Change Accountability Act***, demonstrates the results of B.C.'s work to meet its climate targets. Highlights from the report include: (i) B.C.'s net greenhouse gas emissions have fallen 5% since 2018; (ii) methane emissions from the oil and gas sector have fallen by 50% (surpassing the goal to reduce by 45% by 2025); (iii) zero-emission vehicles now account for more than 22% of all new passenger-vehicles sales; (iv) the number of public charging stations in B.C. grew by 24% to more than 3,800 in 2022; (v) in an 84% increase from the previous year, more than 13,000 CleanBC rebates for residential retrofits were provided, including 6,000 incentives to make heat pumps more affordable; and (vi) B.C. is investing in 59 infrastructure projects throughout the province for renewable energy, clean transportation and efficient buildings.

— **B.C. moves forward initiatives under the Climate Preparedness and Adaption Strategy:** The Climate Preparedness and Adaption Strategy was released on June 22, 2022 as a part of the CleanBC Roadmap to 2030. On July 20, 2023, B.C. announced that it had launched the one-year Indigenous climate-resilience capacity-building pilot program funded with C$2 million under the Strategy. The program is being delivered by the Coastal First Nations-Great Bear Initiative and the First Nations Emergency Services Society. The pilot project is intended to provide community support (including mentorship, knowledge projects, training, and a learning network) to advance climate resilience among Indigenous groups. In addition, during 2023 B.C. released its intentions paper for the Watershed Security Strategy and Fund and provided a summary of consultation on a proposed Flood Strategy.

— **B.C. establishes new energy action framework:** Further building on actions outlined in the CleanBC Roadmap to 2030, on March 14, 2023, B.C. released an energy action framework, which provides that B.C. will:

  — require all proposed LNG facilities in or entering the environmental assessment process to pass an emissions test and provide a credible plan to be net zero by 2030;

  — impose a regulatory emissions cap for the oil and gas industry to facilitate meeting B.C.'s 2030 emissions-reduction target for the sector;

  — establish a clean energy and major projects office (which was established in May 2023) to fast-track investment in clean energy and technology and create jobs in the clean energy transition; and

  — create a BC Hydro task force to accelerate electrification efforts in B.C. by providing renewable electricity to more homes, businesses and industries.

- **B.C. amends the *Zero-Emission Vehicles Amendment Act:*** Bill 39: the ***Zero-Emission Vehicles Amendment Act*** received royal assent on November 30, 2023. These amendments have increased the percentage of new zero-emission vehicles (ZEVs) that automakers (and indirectly their dealers) are required to sell or lease to the following amounts: 26% by 2026, 90% by 2030 and 100% by 2035.

- **B.C. changes building code to support zero-carbon targets:** Effective May 1, 2023, the B.C. Building Code requires 20% better energy efficiency for most new buildings. In addition, B.C. has created a voluntary provincial standard for reducing emissions in new buildings named the Zero Carbon Step Code. These initiatives are a step toward achieving all zero carbon new buildings by 2030 and net-zero energy ready building construction by 2032 (meaning that the site uses 80% less energy than typical new construction), as set forth in the CleanBC Roadmap to 2030.

- **B.C. establishes new *Ecological Reserves Regulation*:** A new ***Ecological Reserve Regulation*** has been established under the ***Ecological Reserve Act***. This new regulation provides BC Parks with the authority to impose penalties on individuals and companies disobeying laws within ecological reserve areas. In addition, the regulations set out a list of prohibitions in ecological reserve areas, including: (a) an absolute prohibition on prospecting for petroleum or natural gas; and (b) a variety of prohibitions subject to obtaining a permit under the *Ecological Reserve Act* (such as prohibitions on felling timber, constructing roads, or establishing buildings).

- **B.C. regulates single use plastics:** On July 14, 2023, the Ministry of Environment and Climate Change Strategy **announced** that the new ***Single-Use and Plastic Waste Prevention Regulation*** will expand its efforts to tackle single-use and plastic items that are difficult to recycle. The requirements to phase out certain plastic and single-use items, which is part of the **CleanBC Plastics Action Plan**, begin to come into force in December 20, 2023 and will be fully in force by July 15, 2024.

- **BC Energy Regulator addresses methane emissions:** Effective January 1, 2024, the ***Dormancy and Shutdown Regulation***, ***Drilling and Production Regulation*** and ***Oil and Gas Processing Facility Regulation*** have been updated in response to the BC Energy Regulator's **review** of methane regulatory requirements in respect of the oil and gas sector. The new requirements include simplified leak detection and repair requirements, and the introduction of continuous monitoring or frequent inspections of unsupervised continuous flares.

- **B.C. introduces modernized emergency management legislation:** On November 8, 2023, the ***Emergency and Disaster Management Act*** came partly into force, with the remaining provisions to come into force via regulations over time. The Minister of Emergency Management and Climate Readiness B.C. **has stated** that this legislation is the first major land-based statute to be co-developed with First Nations to ensure strong alignment with the United Nations Declaration on the Rights of Indigenous Peoples and the *Declaration on the Rights of Indigenous Peoples Act*. The updated emergency response program has been modernized to include the linkage between climate change and increasing emergencies, and recognition of the inherent rights of Indigenous Peoples (in particular, by granting modern treaty nations with significant powers as local authorities during locally declared states of emergency or recovery periods from such emergencies). This legislation stipulates that the statute and regulations be reviewed every five years, to ensure the legislation is appropriate (considering the escalation of emergencies in B.C.). In addition to the new emergency management legislation, on February 21, 2023, B.C. **committed** C$180 million the to the Community Emergency Preparedness Fund to support projects which help local governments and First Nations communities prepare for natural disasters.

- **B.C. recognizes hydrogen as an energy source:** The ***Energy Statutes Amendment Act, 2022*** was passed on November 24, 2022. This legislation significantly amends the ***Oil and Gas Activities Act***, renames it the ***Energy Resources Activities Act***, and names the BC Oil and Gas Commission as the BC Energy Regulator. These amendments largely focus on the broadening of the scope of the *Oil and Gas Activities Act* to include regulation of "hydrogen" as an "energy resource," which is consistent with the province's commitment to a low-carbon economy. The CleanBC Roadmap to 2030 and the **B.C. Hydrogen Strategy** each highlight the importance of hydrogen as a clean energy resource in B.C.'s future. Through **regulations** published during 2023, a significant number of the provisions have come into force.

- Further, on November 23, 2023, the British Columbia Utilities Commission (BCUC) released the **Final Report on the Inquiry into the Regulation of Hydrogen Energy Services**, which concluded the provision of certain hydrogen energy services for compensation is captured within the definition of public utility under

the ***Utilities Commission Act***. Accordingly, the BCUC has recommended that the province develop certain exemptions for hydrogen energy services under the *Utilities Commission Act* and institute procedures to register and regulate hydrogen energy providers.

- **Amendments to environmental legislation emphasize remediation and restoration:** **Bill 29**, which received royal assent on November 8, 2023, proposes amendments to the ***Environmental Management Act*** which largely focus on the decommissioning and closure of responsible persons for specified facilities. "Responsible persons" under the amendments include those who own or are in control of or responsible for the use of a facility and include any person who has an interest or estate in the facility. The amendments also allow the provincial director to serve decommissioning and closure-related orders (including financial assurance requirements) for responsible persons in respect of specified facilities (being facilities used for a prescribed industrial or commercial purpose or activity that could cause pollution or contamination following closure). In addition to Bill 29, amendments have been made to the ***Dormancy and Shutdown Regulation*** *and* ***Drilling and Production Regulation*** related to the restoration of dormant and former oil and gas sites. As of January 1, 2024: (a) firm timelines for decommissioning, assessment, and restoration of pipelines and certain facilities under the *Dormancy and Shutdown Regulation* will be effective, subject to the regulator's power to approve alternative site-specific timelines; and (b) firm timelines on suspending a facility following inactivity and for notification of such suspension under the *Drilling and Production Regulation* will also become applicable.

- **Sierra Club of British Columbia Foundation challenges adequacy of climate change reporting:** On January 17, 2023, the B.C. Supreme Court released a **decision** confirming that the Ministry of Environment and Climate Change Canada had not breached its statutory obligations under the *Climate Change Accountability Act* (CCAA) by not including plans to continue progress toward meeting the provincewide targets set for 2025, 2040, 2050 and the oil and gas sector target set for 2030. However, the Minister was not successful in seeking a declaration from the Court that its reporting obligations under the CCAA were non-justiciable due to the political nature of the greenhouse gas (GHG) emissions reduction plans and the Minister's accountability for those plans to the legislative assembly under the CCAA. This decision incrementally opens the door for courts to hold governments accountable, where across Canada, at the federal and provincial levels, governments are grappling with their obligations under newly enacted requirements under climate change legislation. This represents a significant step in the development of public interest climate change litigation in Canada, where previously, the Federal Court ruled that Charter claims brought on the basis of a government's failure to stringently regulate emissions could not be advanced in the courts on the basis that they are non-justiciable.

- **B.C. enacts *Low Carbon Fuels Act*:** On January 1, 2024, the ***Low Carbon Fuels Act*** came into force, repealing the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act* and its associated regulations. This new legislation and regulations implement similar provisions to the predecessor legislation and regulations including fuel eligibility, labelling requirements, requirements for determining the carbon intensity of a fuel, variables to be used in the compliance unit formula, and compliance reporting requirements. One notable new requirement is the inclusion of a requirement for the use of sustainable aviation fuel, making B.C. one of the first jurisdictions to do so.

ALBERTA

— **Alberta's Renewable Inquiry and Related Pause:** As discussed in detail within the **Alberta Regional Overview**, following a pause by the government of Alberta issued **order-in-council** (171/2023) (the Order), pursuant to which, the Alberta Utilities Commission (AUC) was ordered to inquire into and report to the Minister of Affordability and Utilities on the ongoing economic, orderly and efficient development and operation of electricity generation in Alberta (the Inquiry). As discussed within the **Alberta Regional Overview**, Module A of the Inquiry will among other things, result in report on the AUC's consideration regarding reclamation security requirements and the impacts of renewable power plants on specific types of lands. It will be important to monitor the developments of this Inquiry and any new requirements that may be imposed on renewable generation facilities in Alberta.

— **Amendments to Alberta's TIER Regulation:** The ***Technology Innovation and Emission Reduction Regulation*** (TIER Regulation), enacted under Alberta's ***Emissions Management and Climate Resilience Act***, governs Alberta's industrial greenhouse gas emissions pricing regime and emissions trading system. Facilities regulated under the TIER Regulation must reduce emissions to meet facility benchmarks. Facilities regulated by TIER Regulation, or those which opt in, are exempt from paying the federal fuel charge. The TIER Regulation also establishes the **Alberta Emission Offset System**. In accordance with its terms, the TIER Regulation must be periodically reviewed giving stakeholders an opportunity to provide input on improvements to the TIER system and to enable the regime to meet the updated federal benchmark criteria for the assessment of carbon pricing systems for 2023 to 2030.

The government of Alberta completed its review of the TIER Regulation in December of 2022 and released the ***Technology Innovation and Emissions Reduction Amendment Regulation*** (the Amendment Regulation) and the ***Administrative Penalty Amendment Regulation***, imposing certain amendments and changes that came into force on January 1, 2023. The amendments enacted by the Amendment Regulation maintain the TIER Regulation's compliance with federal stringency standards, ensuring that Alberta's carbon pricing system remains in place in the province instead of the federal fuel charge.

The amendments to the TIER Regulation include:

— **Regulatory stringency:** Opt-in threshold for emissions-intensive and trade-exposed industry is reduced from 10,000 tonnes of carbon dioxide equivalent (CO_2e) per year to 2,000 tonnes CO_2e per year.

— **Benchmarks:** A 2% annual tightening rate will apply to facility-specific benchmarks and high-performance benchmarks. For oilsands mining, in situ and upgrading, the annual tightening rate will be 4% in 2029 and 2030. Additional high-performance benchmarks will be released in early 2023.

— **Credit expiration:** Emission performance credit (EPC) and offset expiry is reduced from the current nine-year and eight-year periods, respectively, to five years for EPCs and offsets issued in 2023 or later. Sequestration credits must be used for a year within the six-year period beginning in the year in which the net geological sequestration of the associated emission offset occurred.

— **Credit use limit:** The credit use limit in which emitters can use EPCs, offsets and sequestration credits to comply with emission targets will be 60% in 2023, 70% in 2024, 80% in 2025 and 90% in 2026 and on.

— **Carbon price:** A Ministerial Order will set the TIER Fund Price for 2023 to 2030, aligning the provincial fuel price with federal requirements. The price will increase annually (by C$15 increments) starting at C$65 in 2023 and will increase to C$170 in 2030.

Adding further support to Alberta's CCUS regime, the Amendment Regulation establishes "sequestration credits" and "capture recognition tonnes" in connection with CCUS projects in the province. Sequestration credits will enable recognition under the federal ***Clean Fuel Regulations*** and must be used for a year within the six-year period beginning in the year in which the net geological sequestration of the associated emission offset occurred. Sequestration credits can only be issued for converted offsets that meet the following requirements:

1. the emissions for net sequestration must meet the requirements for sequestration under the TIER Regulation;
2. the geological sequestration must have occurred in or after 2022; and
3. the sequestered CO_2e for the emission offset must have been captured by a large emitter or at an opted-in facility.

— **Alberta Environment lays charges under *Emissions Management and Climate Resilience Act*:** For the first time, **Alberta Environment and Protected Areas** (AEPA) **charged** an Alberta based environmental services company that provided third-party verification services in connection with the compliance and reporting obligations required under the ***Emissions Management and Climate Resilience Act*** (Emissions Management Act) and the TIER Regulation. The entity and individual charged collectively face 25 charges for, among other things, allegedly contravening the Emissions Management Act by providing false information and lacking the necessary qualifications to provide their verification service. Each of the charges carry the potential for penalties, ranging between C$50,000 and C$100,000 for an individual and C$500,000 and C$1,000,000 for a corporation.

The legitimacy and validity of the TIER Regulation, the required filings and any offsets, EPCs or sequestration credits is critical to Alberta's carbon market. In the case where an EPC, offset or sequestration credit, as the case may be, referenced in an annual compliance report is subsequently found to be invalid, the person responsible for the regulated facility to which such compliance report pertains must, within 60 days of receiving notice of the cancellation or direction from AEPA, do one of the following:

— pay into the TIER Fund an amount equal to the amount it would have had to contribute to obtain one fund credit for the year the invalidated offset, EPC or sequestration credit was used; or

— use another unused offset, EPC or sequestration credit, in place of the invalidated offset, EPC or sequestration credit.

It is important to note that such curative requirements are operative notwithstanding that such invalidated offset, EPC or sequestration credit may have been verified by a third-party assurance provider, as required under the TIER Regulation. Such verification, while indicative of the validity of such credits, is not conclusively determinative of their validity. Accordingly, it is critical for those transacting in any offsets, EPCs or sequestration credits to not view successful verification as a substitute for the proper allocation of invalidation risk as between buyer and seller in the operative transaction documents.

— ***Qualex-Landmark Towers Inc v. 12-10 Capital Corp,* (2023 ABKB 109):** On February 27, 2023, the Alberta Court of King's Bench granted a pre-judgement attachment order, which secured the cost of remediating environmental contamination migrating from lands held by 12-10 Capital Corp (the Respondent) to lands held by Qualex-Landmark Towers Inc. (the Appellant) in priority over other registered creditors to secure remediation costs from contamination that migrated from the Respondent's land. The Appellant sought the order to preserve the proceeds of sale of the Respondent's property up to the cost of the remediation in respect of the Appellant's property. The Respondent was likely insolvent, with mortgages registered against its property which exceeded the value of that property. The Court ultimately held that the Appellant had a reasonable likelihood of establishing that its claim for environmental remediation ranks in priority to the mortgages, and accordingly was prepared to preserve proceeds of the sale of the Respondent's property by granting the attachment order pending a full trial of the issues.

This is the first case that has applied the Supreme Court of Canada's decision in *Orphan Well Association v. Grant Thornton Ltd.*, 2019 SCC 5 (where the Supreme Court held that environmental reclamation obligations obtain a super priority over secured creditors) to a private dispute. The court expanded the reasoning in the Supreme Court's decision beyond formal insolvency proceedings, stating "the super-priority charge over the real property of the corporation to remediate likely arises coincidental with the contamination and will hang over the real property like an umbrella until the environmental remediation obligation is satisfied." The fast track appeal of this decision was heard on December 4, 2023, and the decision has, as of yet, been held in reserve. The appeals focussed on whether a common law super-priority right can exist in favor of a private party in respect of environmental obligations that is capable of subordinating rights of pre-existing secured lenders.

ONTARIO

— **Efficiency regulation under the *Electricity Act, 1998*:** Between August 10, 2022 and September 24, 2022, the Ministry of Energy (MOE) posted a **proposal** to amend ***O. Reg. 509/18, Energy and Water Efficiency – Appliances and Products*** (O. Reg. 509/18) made under the ***Electricity Act, 1998*** (the *Electricity Act*) on the Environmental Registry of Ontario and the Regulatory Registry, for a 45-day public review period. Thereafter, on November 25, 2022, an amendment to O. Reg. 509/18 was filed to update testing methods and efficiency requirements for specific appliances and products to enhance harmonization with industry standards, such as those prescribed by Natural Resources Canada and the United States Department of Energy. The amendment is expected to reduce the environmental impact of energy use from the regulated products and encourage energy conservation by increasing the efficiency of such products sold or leased in Ontario. This, in turn, can reduce the consumption of fossil fuels and the release of pollutants to the environment. The amendment took effect on January 1, 2023, and some of the specific products for which it applies include geothermal heat pumps, air conditioners, commercial water heaters, commercial gas furnaces and liquid-filled transformers.

— **Energy reporting and conservation and demand management plans for the broader public sector:** In February of 2023, the Ontario provincial government introduced Ontario Regulation 25/23 (**O. Reg. 25/23**) under the *Electricity Act* requiring certain public agencies, including municipalities, municipal service boards, school boards, post-secondary educational institutions, and hospitals, to report on their energy consumption and GHG emissions annually. O. Reg. 25/23 mandates that public agencies develop and update every five years, an energy conservation and demand management plan that also includes the following:

  — the agencies' conservation goals and objectives;

  — the agencies' proposed conservation measures;

  — the agencies' cost and savings estimates; and

  — a description of any renewable energy generation facilities the agency uses, including the amount of energy it generates annually.

Public agencies are required to report energy usage data every year by July 1. While the government phases in the program, the reporting schedule for 2023 required agencies to report their 2021 energy data by October 31, 2023. In 2024, agencies must report their 2022 and 2023 energy usage data. Thereafter, agencies will have to report their energy usage data for each previous calendar year every five years.

- **Ontario Clean Energy Credits (CECs):** On March 29, 2023, **Ontario launched a CEC registry** administered by the Independent Electricity System Operator (IESO). CECs are electronic certificates used to demonstrate that clean energy from Ontario based generation has been acquired in order to meet a voluntary target. Each CEC represents 1 MW hour of clean energy that has been generated and is intended to be exclusively purchased and claimed (or retired) by load customers within Ontario. The CEC registry allows Ontario businesses to purchase any combination of clean energy credits from nuclear, wind, solar, hydro and bioenergy generation in Ontario. Eligible Ontario-based non-fossil fuel generation facilities can register online to have the generation from the facilities verified and tracked and proceeds from the sale of the CECs are set to help create the government's **Future Clean Electricity Fund**. The fund is anticipated to keep costs down for electricity ratepayers by supporting the development of new clean energy projects and addressing the barriers to resource development.

- **MOE and IESO Interruptible Rate Pilot:** In August 2022, the MOE **issued a formal correspondence**, extending an invitation to the IESO to engage in collaborative efforts directed at designing a comprehensive three-year **Interruptible Rate Pilot** (IRP). This pioneering initiative was formulated to furnish substantial electricity load customers with an interruptible rate structure for **Global Adjustment** (GA) charges throughout the pilot term. In reciprocal commitment, these entities agreed to interrupt their demand during specified interruption events, as identified by the IESO. In response to the MOE, the IESO submitted a detailed pilot design proposal in December 2022. On February 2, 2023, the Minister drafted a **letter affirming its support for the pilot**, followed by an **official directive** on February 9, directing the IESO to design and administer the IRP. The designated application end time for the IRP occurred on March 31, 2023, marking the conclusion of prospective participation. In July 2023, successful applicants began participating and testing a new option to reduce their GA charges in exchange for agreeing to temporarily lower demand during periods of high electrical usage. The IESO anticipates that participants in the pilot may benefit from greater cost and planning certainty, particularly for electricity loads that experience challenges in identifying and responding to top peak demand hours while participating in **Ontario's Industrial Conservation Initiative** (ICI).

- **Updates to Ontario's transition to Emissions Performance Standards:** Ontario's transition from the federal Output Based Pricing System for industry-specific emissions to the **Ontario Emission Performance Standards** (EPS) began on January 1, 2022. The EPS program requires regulated facilities to meet an annual baseline amount of GHG emissions that is calculated using an industry-specific performance standard. If a regulated facility exceeds this baseline emissions limit, it will be required to pay a carbon price for the portion of the emissions output that is in excess of this limit. In 2023, **significant amendments** to the EPS took effect to better align them with more stringent federal standards for the program period between 2023 and 2030. The changes include increasing the carbon price under the EPS program, strengthening performance standards for electricity generation using fossil fuels, and adjusting stringency factors for covered facilities. Key

modifications also encompass expanding the EPS program's scope to cover more industries, addressing the treatment of retrofits and expansions, and streamlining standards for cogeneration. The amended regulations came into effect on January 1, 2023, with specific provisions applying immediately to maintain harmonization with federal reporting requirements.

— **Virtual net metering arrangements for ICI participants:** On November 2, 2023, the Ontario provincial government released its **proposal** to amend **O. Reg. 429/04** under the *Electricity Act*. The proposed amendments seek to foster the expansion of clean energy generation within the province by granting ICI participants the ability to counterbalance their facility's energy demand during the highest five peak hours of a specified base period through power purchase agreements (PPAs) with renewable generation facilities that are not connected behind the facility's meter. Under the proposal, the range of eligible technologies include wind, solar, small hydroelectric (i.e., less than 10 MW), biofuel and battery storage. Drawing parallels with "virtual" net metering arrangements for eligible ICI participants, the proposal would allow the contracted generation to be treated as if it were supplied to the ICI participant from behind the meter. This treatment is instrumental in determining GA charges. Beyond contributing to system benefits, this arrangement has the potential to bolster industrial competitiveness within the province and support the development of new clean generation. The comment period for the proposal ended on December 17, 2023 and if adopted, the amendments are set to take effect on May 1, 2024.

QUÉBEC

— **New trigger to provincial Environmental Impact Assessment procedure:** In July 2023, the ***Regulation respecting the environmental impact assessment and review of certain projects*** was amended to add new projects related to energy storage equipment that are now subject to the Québec environmental impact assessment procedure set out under the ***Environment Quality Act***. Since July 20, 2023, these new triggers are in force: (i) the construction of a plant performing, for the purpose of manufacturing cells, electrochemical accumulators or batteries, any of the following activities: manufacturing of active materials for electrodes, manufacturing of separators or assembly of electrodes (Plant) when such Plant has a maximum annual production capacity equal or greater than 60,000 metric tons; (ii) the increase of the maximum annual production capacity of a Plant that would reach or exceed 60,000 metric tons; or (iii) for a Plant whose maximum annual production capacity is equal to or greater than 60,000 metric tons, any increase of 50% or more of that capacity or any increase of that capacity that results in the expansion of 25% or more of the Plant's operation area. Concurrently, the triggers with respect to the manufacturing of motor vehicles were revoked.

— **Omnibus regulations:** In June 2023, the government of Québec published 23 omnibus regulations in support of the modernization of the *Environment Quality Act* and to implement certain measures provided under ***An Act mainly to reinforce the enforcement of environmental and dam safety legislation, to ensure the responsible management of pesticides and to implement certain measures of the 2030 Plan for a Green Economy concerning zero-emission vehicles***. Some of the amendments may impact the power industry, for example: the revision of the requirements for the dam safety review study and the simplification of the filing and declaration process with the relevant authority under the ***Dam Safety Regulation*** (Québec).

Most of the amendments to the 23 omnibus regulations have already come into effect in July 2023 and others will gradually come into force on December 18, 2023 and January 1, 2024.

FEDERAL

— **Commissioner of the Environment and Sustainable Development issues report on 2030 Emissions Reduction Plan:** Pursuant to obligations under the ***Canadian Net-Zero Emissions Accountability Act***, on September 8, 2023 the Commissioner of the Environment and Sustainable Development issued **Report 6—Canadian Net-Zero Emissions Accountability Act—2030 Emissions Reduction Plan** for the period of June 2021 to August 17, 2023, respecting the federal government's implementation of mitigation measures to reduce greenhouse gas emissions. The report ultimately concluded that "mitigation measures in the 2030 Emissions Reduction Plan were insufficient to meet Canada's 2030 target" because, "although the plan was designed with measures that could deliver sizable reductions, fragmented accountabilities for reducing emissions and no prioritization of measures were barriers to success."

— **Funding clean initiatives a priority in 2023:** During 2023, the federal government has continued to

provide **significant funding** for the clean energy transition, including nearly C$3 billion to the **Smart Renewables and Electrification Pathways Program**, C$10 billion in low-cost financing from the Canada Infrastructure Bank for clean electricity projects, and C$520 million for the **Clean Energy for Indigenous, Rural and Remote Communities programs**. The **Low Carbon Economy Fund** continues to support projects that reduce greenhouse gas emissions and generate clean growth and create job opportunities for Canadians. Additional funding initiatives are recognized below.

— **Federal government launches the National Adaption Strategy:** After two years of engagement with provinces, territories, Indigenous partners, experts and stakeholders, on June 27, 2023, the federal government launched the **National Adaption Strategy**, which lays out a framework to reduce the risk of climate-related disasters, improve health outcomes, protect nature and biodiversity, build and maintain resilient infrastructure and support a strong economy. The **Government of Canada Adaptation Action Plan** was also updated to include new federal investments and initiatives related to flooding, freshwater, supply chains, and security at the same time (and which resulted in additional funding for the Disaster Mitigation and Adaptation Fund, or DMAF). Accordingly, January 16, 2023, Infrastructure Canada **announced** that it was accepting applications for new projects under DMAF, which either involve new construction of public infrastructure or modification of existing public infrastructure to mitigate impacts of natural disasters and climate-related risks.

— **Federal government launches Critical Minerals Infrastructure Fund:** On December 9, 2022, the federal government released **Canada's Critical Minerals Strategy**. This highly anticipated strategy is a key component of Canada's efforts to both access and supply critical minerals and to support clean energy production. On October 31, 2023, the Minister of Energy and Natural Resources announced that the federal government is launching a **C$1.5 billion infrastructure fund** in order to: (a) address clean energy and transportation infrastructure gaps to enable sustainable critical minerals production; (b) reduce emissions in operations that produce critical minerals by increasing access to and integration of renewable and non-remitting energy sources or energy grids; and (c) advance reconciliation with Indigenous groups by supporting Indigenous consultation and participation, as well as benefits from infrastructure projects that enable critical minerals development. This key component of the Critical Minerals Strategy provides funds over the next seven years to support clean energy and transportation projects that will enable critical mineral development. The fund will provide up to C$50 million per project for non-governmental applicants and up to C$100 million per project for provincial and territorial governments.

— **Federal government continues to pursue 30x30 goal:** The federal government has **pledged** to conserve 30% of Canada's land and water by 2030. These efforts support the reduction of declines in biodiversity, the mitigation of climate change and maintenance of a sustainable economy. On May 15, 2023, the Minister of Environment and Climate Change **launched** consultations with Canadians on the 2030 Biodiversity Strategy for Canada, and on May 17, 2023, the Minister **launched** the Conservation Exchange Pilot, which encourages businesses to invest in biodiversity conservation. On November 3, 2023, the governments of Canada and B.C. and the First Nations Leadership Council signed a tripartite framework agreement to protect and conserve biodiversity, habitats, and species at risk in B.C. Each of B.C. and Canada will invest up to C$500 million over the life of the agreement to support its implementation. On October 10, 2023, Canada **announced** that it had entered into the Canada-Nova Scotia Nature Agreement, which will support nature conservation and protection across Nova Scotia. Under this agreement, the government of Canada will invest up to C$28.5 million over three years to implement the agreement. The agreement will also support the Mi'kmaq of Nova Scotia's leadership in conservation and will support Nova Scotia in reaching its goal to increase the amount of protected and conserved areas in the province by 82,500 hectares by March 2026.

— **Federal government introduces a framework to cap oil and gas emissions:** On December 7, 2023, the federal government introduced a **draft framework** to cap oil and gas emissions. This **framework** is intended to support Canada's goals to reach net zero by 2050, and would apply to LNG facilities as well as upstream oil and gas facilities (including offshore facilities). The cap-and-trade system will be implemented through regulations under **the *Canadian Environmental Protection Act*** (CEPA) and will be responsive to several key principles: (a) decline of emissions to meet net zero by 2050; (b) creating the legal upper bound on emissions (being the maximum emissions the whole sector may be allowed to emit per year) in a manner responsive to technically achievable emissions reductions and the global demand for oil and gas; (c) minimal administrative burden; and (d) ongoing monitoring and regular review of the standards. The government of Canada is accepting formal written submissions in response to the framework until February 5, 2024, after which it plans to publish the proposed regulations in the *Canada Gazette*, Part I for the 60-day comment period. Final publication of the regulations is slated for 2025, with the first reporting obligations to commence in 2026.

— **Federal government releases framework to phase out fossil fuel subsidies:** On July 24, 2023, the Minister of Environment and Climate Change released the **Inefficient Fossil Fuel Subsidies Government of Canada Self-Review Assessment Framework** and the **Inefficient Fossil Fuel Subsidies Government of Canada Guidelines**. These documents will support the government's focus on clean energy and net-zero initiatives and the decarbonization of Canada's oil and gas sector. Under the framework, subsidies will be considered "inefficient" unless they meet one of the following criteria:

  — enable significant net greenhouse gas emissions reductions in Canada or internationally in alignment with Article 6 of the Paris Agreement;

  — support clean energy, clean technology, or renewable energy;

  — provide essential energy service to a remote community;

  — provide short-term support for emergency response;

  — support Indigenous economic participation in fossil fuel activities; or

  — support abated production processes, such as carbon capture, utilization, and storage, or projects that have a credible plan to achieve net-zero emissions by 2030.

  The initiatives under the framework build on **Canada's commitment under the 2021 Glasgow statement** to end new direct public support for the fossil fuel energy sector.

— **Amendments to CEPA under Bill S-5:** In June 2022, the Senate passed **Bill S-5** (*Strengthening Environmental Protection for a Healthier Canada Act*) to amend CEPA. On June 13, 2023, the bill **received** royal assent, amending the preamble to CEPA to recognize that every individual in Canada has a right to a healthy environment. With these amendments, s. 2 of CEPA requires that the federal government protect this right, and that an implementation framework be developed to consider how this right will be administered under CEPA. The government **indicates** that this framework will be developed by June 2025. Other amendments include creating a risk assessment Plan of Chemical Management Priorities (which will set out a multi-year assessment of substances and activities), and a commitment to consider the cumulative effects of these assessments on vulnerable populations.

— **Federal government launches new Offset System Protocol:** The ***Canadian Greenhouse Gas Offset Credit System Regulations*** (GHG Offset Regulations), established under Part 2 of the ***Greenhouse Gas Pollution Pricing Act* (GGPPA)**, were published in the **Canada Gazette, Part II** on June 8, 2022. The Greenhouse Gas (GHG) Offset Credit System enables project proponents to generate federal offset credits if they register and implement projects that reduce GHG emissions using a published federal GHG offset protocol. Offset credits can be sold and used for

compliance by facilities covered in the federal Output Based Pricing System, or sold and used by others who are looking to meet voluntary climate commitments. On February 24, 2023, the Minister of Environment and Climate Change **announced** that under ***Reducing Greenhouse Gas Emissions from Refrigeration Systems Version 1.0*** certain businesses upgrading their refrigeration and air-conditioning systems to ones that use refrigerants with lower global warming potentials will be eligible to generate offset credits under the Greenhouse Gas Offset Credit System. This offset credit system is to incentivize businesses to undertake refrigeration transition projects that will reduce greenhouse gas emissions that cause climate change. The GHG Offset Credit System is now accepting applications for project registration under both the *Reducing Greenhouse Gas Emissions from Refrigeration Systems Version* and the **Landfill Methane Recovery and Destruction protocol,** which was published last year.

— **Release of draft *Clean Electricity Regulations:*** On August 10, 2023, the federal government released a draft of the ***Clean Electricity Regulations*** (CER), which will help drive progress toward a net-zero electricity grid by 2035. The CER, which are made under CEPA, are part of a suite of measures by the government of Canada from the 2030 Emissions Reduction Plan to transition to clean energy. While the draft regulations set a stringent pollution emissions standard, they do not prescribe specific technologies. This technology-neutral approach is intended to provide flexibility to provincial, territorial and municipal decision-makers as they transition to clean energy. The federal government **provides** that the draft CER set "a clear signal for transitioning toward a clean grid, while including flexibilities to avoid stranding large capital assets, and to enable electricity systems to continue to provide reliable, affordable power." For example, fossil-fuel generation may have a limited role past 2035 — where needed to maintain affordable and reliable power. Due to a lack of commercially available technology that is capable of replacing diesel generation in certain respects, remote communities are exempt from the CER.

— The Alberta government has **asserted** that the draft CER are unconstitutional, and has encouraged the federal government to endorse Alberta's plan to achieve carbon neutrality by 2050. On November 27, 2023, the government of Alberta **gave notice** that it intends to invoke a resolution under the ***Alberta Sovereignty within a United Canada Act*** in response to the draft CER. The resolution directs certain provincial entities to not enforce or comply with the CER once in force, "to the extent legally permissible." Similarly, the government of Saskatchewan intends to use ***The Saskatchewan First Act*** to establish a tribunal to study the economic effects of the CER. Accordingly, there is a high likelihood that the CER, once in force, will be subject to constitutional challenge.

— **Clean Fuel Regulations come into force:** On July 1, 2023, the ***Clean Fuel Regulations*** (CFR) came into force. The objective of the clean fuel standard is to achieve 30 million tonnes of annual reductions in GHG emissions by 2030. The CFR require liquid fossil fuel primary suppliers (i.e., producers and importers) to reduce the carbon intensity (CI) of the liquid fossil fuels they produce here or import into Canada. The CFR has also established a credit market, whereby the annual CI reduction requirement can be met via three main categories of credit-creating actions: (i) actions that reduce the CI of the fossil fuel throughout its life cycle; (ii) supplying low-carbon fuels; and (iii) specified end-use fuel switching in transportation.

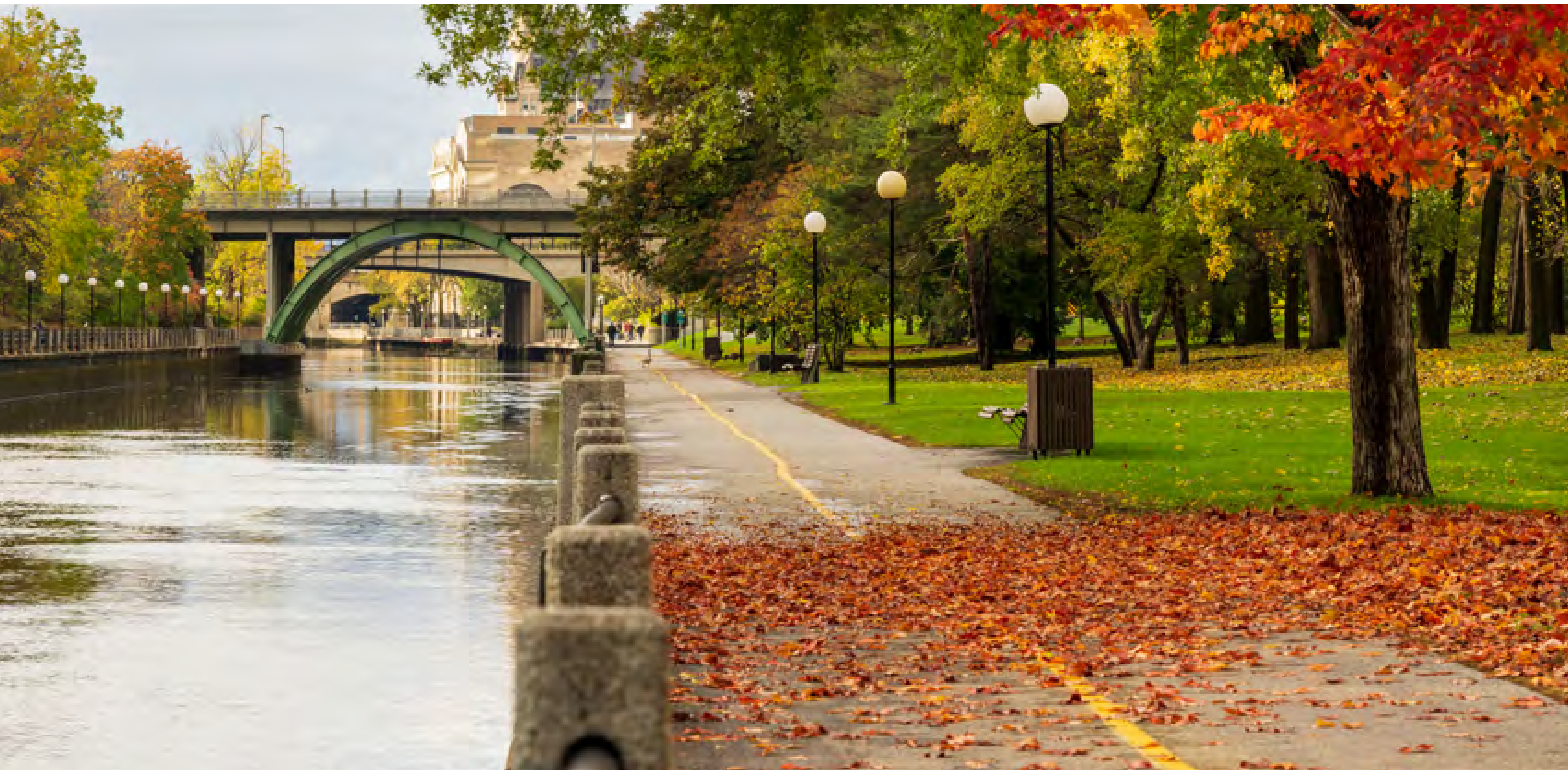
— **Federal government publishes draft methane regulations to support cleaner energy and climate action:** On December 4, 2023, the Minister of Environment and Climate Change **announced** that Canada published **draft oil and gas methane regulations** to cut emissions, which broadly align with regulations in the U.S. and with calls from the International Energy Agency to reduce methane emissions from the energy sector by 75% by 2030. The publication of these regulations is a step forward in Canada's **Methane Strategy**.

— **Federal government publishes amendments to OBPS Regulations:** The ***Output-Based Pricing System Regulations*** (OBPS Regulations), under the ***Greenhouse Gas Pollution Pricing Act*** (GGPPA), apply in the backstop jurisdictions listed on Part 2 of Schedule 1 to the GGPPA. On November 22, 2023, the ***Regulations Amending the Output-Based Pricing System Regulations and the Environmental Violations Administrative Monetary Penalties Regulations*** were published in the *Canada Gazette*. These regulations, made under ss. 192 and 193 of the GGPPA, add new and amend existing output-based standards (OBSs) and improve the implementation, reporting accuracy and voluntary participation provisions. In addition, the updated OBPS Regulations introduce a 2% fixed annual percentage tightening rate to most OBSs from 2023 onward. For sectors with a high risk of impacts from competition and of carbon leakage resulting from carbon pricing, the amendments apply an adjusted tightening rate of 1% from 2023 onward. Further, the *Quantification Methods for the Output-Based Pricing System Regulations*, a technical document that contains the detailed emissions quantification methods previously included in Schedule 3 to the OBPS Regulations, were **published** in December 2023.

CONSTITUTIONAL CHALLENGES TO FEDERAL ENVIRONMENTAL OVERSIGHT

In the last year, two significant court cases held that certain federal environmental legislation and/or regulations were unconstitutional. These decisions introduce significant uncertainty into the future with respect to the ambit of federal jurisdiction over environmental matters and may foreshadow continued challenges to efforts by the federal government to protect the environment.

— **Federal *Impact Assessment Act* found unconstitutional:** On October 13, 2023, the Supreme Court of Canada **held** that the "designated projects" scheme in Canada's ***Impact Assessment Act*** (IAA) and ***Physical Activities Regulations*** (Regulations) is unconstitutional. While this decision confirms that the federal government has the power to enact broad impact assessment laws and consider a wide range



of factors when conducting assessments, the federal impact assessment scheme may only target those projects that can result in adverse federal effects. In particular, where the federal government does not have jurisdiction over a specific activity (e.g., mining operations), legislative requirements must focus on the federal aspects of the activity and avoid regulating the activity itself.

On October 13, 2023, the Impact Assessment Agency of Canada stated that it accepted the decision, and that the government of Canada will work quickly to collaborate with provinces and Indigenous groups and improve the legislation through Parliament. On October 26, 2023, the government of Canada provided interim guidance on the administration of the *Impact Assessment Act* pending legislative amendments. While the guidance is not particularly detailed, it does make it clear that the Impact Assessment Agency will continue to advance ongoing impact assessments that are already in progress; however, the Agency will not make "decisions" to designate projects as requiring a federal assessment until the new legislation is introduced.

— **Federal Court finds single-use plastics plan unconstitutional:** On November 16, 2023, the Federal Court **held** that the inclusion of all "Plastic Manufactured Items" (PMIs) in the List of Toxic Substances in Schedule 1 of the ***Canadian Environmental Protection Act*** (CEPA) was unreasonable and unconstitutional, which is the basis upon which the federal government sought to ban single-use plastics through the ***Single-use Plastics Prohibition Regulations***. The Court held that the government did not have sufficient evidence to conclude all PMIs were toxic, and it only had authority to regulate substances for environmental protection if they are listed as toxic under CEPA. The federal government has **indicated** it plans to appeal this decision. While the regulations are still in force, the matter directly challenging the regulations by Petro Plastics Corp., RPUC and Oregon Precision Industries has been stayed pending outcome of the decision in respect of the PMI designation under CEPA. As the decision has now been issued, the challenge to the regulations can move forward.

THE YEAR AHEAD

BRITISH COLUMBIA

- **Further Actions to Implement CleanBC Roadmap to 2030:** In 2024, it is expected that the B.C. Ministry of Environment will continue to develop and introduce various initiatives to implement the CleanBC Roadmap to 2030, including initiatives under the Strategy Climate Preparedness and Adaption Strategy. Specific initiatives that are predicted to be addressed in 2024 are the implementation of new carbon pollution standards for new buildings, implementation of the new output-based pricing system on carbon pollution for large industrial operations (effective April 1, 2024), implementation of the new energy action framework, continued development of the provincial disaster and climate risk and resilience assessment, implementation of a regulatory framework to reduce methane emissions from the oil and gas sector, and completion of B.C.'s electric highway charging network (providing charging stations for electric vehicles) and introduction of a comprehensive clean transportation plan.

- **BC Energy Regulator seeks feedback on environmental legislation:** The BC Energy Regulator is accepting written submissions from the public until December 29, 2023 as part of its comprehensive review of the regulatory framework in respect of manufacturing, associated on-site storage and pipeline transportation of hydrogen, ammonia and methanol. According to the proposed engagement timeline, the BC Energy Regulator will continue engagement on regulatory proposals into 2024 (with an updated regulatory framework to be implemented in 2026).

- **Enforcement of Climate Change legislation:** While Sierra Club of British Columbia was not successful in demonstrating that the Minister's 2021 Climate Change Accountability Report failed to meet the reporting requirements under the CCAA, the determination that the courts have the power to enforce reporting requirements mandated in British Columbia's climate change legislation on the provincial government may generate additional litigation in this area, particularly from environmental public interest groups.

ALBERTA

- **Constitutional debate:** With the federal *Clean Electricity Regulations* looming and the recently announced federal ***Regulatory Framework for an Oil and Gas Sector Greenhouse Emissions Gap***, we anticipate that the constitutional debate that occurred in 2023 with the SCC reference decisions on the *Impact Assessment Act* and single-use plastics, will continue into 2024. The outcome of these challenges will impact energy policy across the country and across a number of industries.

- **Reclamation and end of life requirements for renewables:** An area to monitor in Alberta will be the end of life and reclamation security requirements, which are likely to arise out of the Alberta's pause on renewable development and the AUC Inquiry.

ONTARIO

- **Potential changes to electrical energy efficiency programs under Ontario's *Electricity Act* through public consultation:** Ontario's MOE is actively inviting public engagement via a **voluntary Information Notice** regarding the prospective trajectory of its electricity energy efficiency programs. This initiative precedes the conclusion of ongoing programs and the scheduled initiation of new programs in 2025. In adherence to the requirements of the ***Environmental Bill of Rights, 1993***, the MOE is committed to sharing a comprehensive policy proposal related to this programming on the provincial Environmental Registry. This step is designed to facilitate a thorough public review process, ensuring transparency prior to the finalization and implementation of the proposed policies.

QUÉBEC

— **New rules for the cap-and-trade system for 2024-2030 in effect:** Following the introduction of the **amendments** to the ***Regulation to amend the Regulation respecting a cap-and-trade system for greenhouse gas emission allowances*** in August 2022, the new rules for the allocation of carbon emission units free of charge for the 2024-2030 period under the Québec's cap-and-trade system for GHG emissions will be in effect. These new rules provide for a gradual average of a 2.7% yearly decrease in the overall level of allocation of emission units without charge granted to emitters, which will result in an overall increase of the compliance costs. The government of Québec will also consign, on behalf of several emitters, a portion of the emission units for auctioning and the revenues generated will be set aside for the emitter to finance projects related to the reduction of GHG emissions. According to the government of Québec's estimation, these new rules could result in a potential additional financial impact of C$671 million for all industrial companies currently subject to the cap-and-trade system for the period of 2024-2030.

— **Significant Increase of the charges payable for the use of water:** On December 6, 2023, the government of Québec adopted in its final form amendments to the ***Regulation respecting the charges payable for the use of water***. As of January 1, 2024, the charges payable for the use of a volume of water equal or greater than 75,000 L/day will increase from C$2.50/ML to C$35/ML for the targeted sectors, including mining and quarrying extraction and manufacturing activities (e.g., paper, petroleum and coal product, chemical, primary metal, transportation equipment, etc.). Certain other sectors, such as beverage manufacturing, production of water in bottles, and non-metallic mineral product or basic inorganic chemical manufacturing when water is incorporated into the manufactured product, will be exposed to a more significant increase, from C$7/ML to C$150/ML of the payable charges for the use of a volume of water equal or greater than 75,000 L/day. An additional charge of C$350/ML will be payable by producers of water in bottles. Finally, the rates of the charges will be subject to an annual increase of 3%.

— As of January 1, 2026, the obligation to pay charges will be triggered based on the use of a volume of water equal or greater than 50,000 L/day at least one day in a calendar year, which means that a greater number of water users will be subject to such payment.

FEDERAL

— **Continued implementation of the 2030 Emissions Reduction Plan:** In March 2022, the government of Canada introduced **Canada's 2030 Emissions Reduction Plan**, which provides a road map to achieve Canada's emissions reduction target of 40-45% below 2005 levels by 2030. The plan builds upon the actions outlined in Canada's previous climate plans, ***A Healthy Environment and a Healthy Economy*** (December 2020) and the ***Pan-Canadian Framework on Clean Growth and Climate Change*** (2016). The 2030 Emissions Reduction Plan predicts certain initiatives will occur in 2024, including the beginning of a C$200-million investment to retrofit large trucks, a call for proposals to the Clean Transportation R&D program and the completion of negotiations for an internationally legally binding agreement on plastic pollution.

— **Creation of a new Canada Water Agency:** **Bill C-59** (*An Act to implement certain provisions of the fall economic statement tabled in Parliament on November 21, 2023 and certain provisions of the budget tabled in Parliament on March 28, 2023*) was introduced into the House of Commons on November 30, 2023, and envisions the establishment of a new Canada Water Agency which, unlike the **current Canada Water Agency**, is independent from the Ministry of Environment and Climate Change under the *Canada Water Agency Act*. The Canada Water Agency will have the purpose of assisting the Minister of the Environment and Climate Change in performing its duties and exercising its powers in respect of fresh water.

— **Federal government will continue to move forward in regulation of offshore energy sources:** On May 30, 2023, the Minister of Energy and Natural Resources introduced **Bill C-49** (*An Act to amend the Canada—Newfoundland and Labrador Atlantic Accord*

Implementation Act and the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act and to make consequential amendments to other Acts), which would amend the ***Canada–Newfoundland and Labrador Atlantic Accord Implementation Act*** and the ***Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*** to provide a framework for regulatory approvals of offshore wind energy projects. To date, Bill C-49 has completed second reading in the House of Commons and has been referred to the Standing Committee on Natural Resources for further review. In addition, Natural Resources Canada (NRCan) is leading the Offshore Renewable Energy Regulations (ORER) Initiative, which supports the implementation of Part 5 — Offshore Renewable Energy Projects and Offshore Power Lines of the ***Canadian Energy Regulator Act*** (CER Act) through developing modern safety and environmental regulations for offshore renewable energy projects and offshore power lines. Phase 1 and 2 of the ORER initiative engagement process have been completed. Phase 3, the prepublication of the ORER in Part 1 of the *Canada Gazette* for public comments, **had been predicted** to occur in 2023 but has not yet been republished.

— **Amendments to the *Energy Efficiency Regulations, 2016:*** The ***Energy Efficiency Regulations, 2016*** (EER) were implemented in 1995 under the ***Energy Efficiency Act*** (EEA) and are amended regularly to add or update energy efficiency standards, testing standards, or labelling requirements for energy-using products. **Amendment 17** to the EER came into force in June 21, 2023, significantly expanding the list of specified energy-using products, and accordingly the Minister's power "to make technical and administrative changes to regulations to maintain harmonization … with another jurisdiction" in respect of such products (EEA, s. 20.1(2)). According to NRCan **2023-2025 Forward Regulatory Plan**, it will publish further amendments to the EER by the end of 2025. The planned amendments include:

— governor-in-council amendments to update updating or adding energy efficiency or testing standards, as described in the **technical bulletins** released in July 2022, for certain products (including certain air conditioners, heat pumps, water heaters, furnaces, shower heads and air compressors); and

— ministerial Regulations amendments to maintain alignment with regulations in the U.S. for ceiling fan lighting kits, icemakers, metal halide lamp ballasts and microwave ovens.

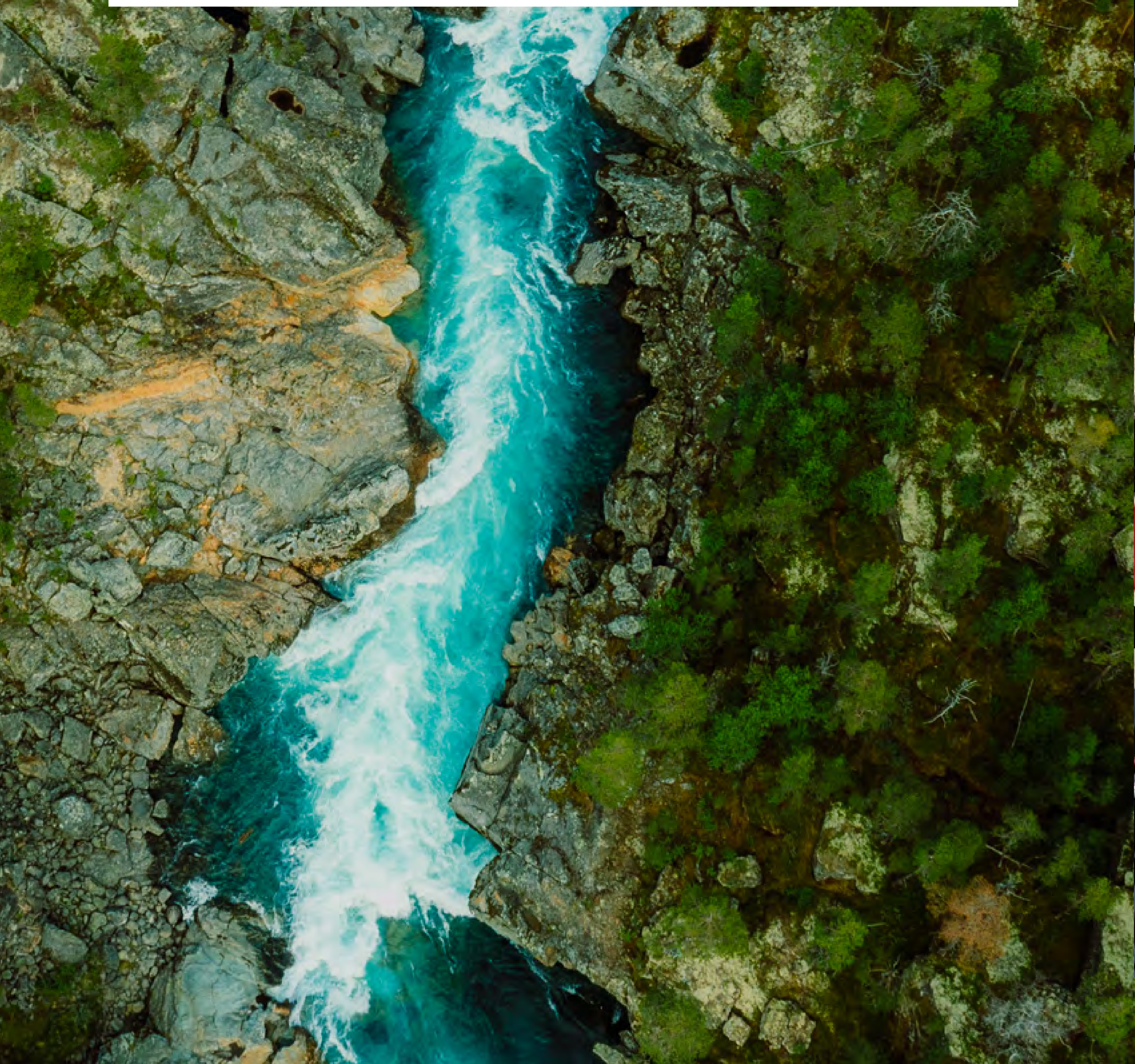
In addition, on August 19, 2023, NRCan published a notice in Canada Gazette, Part I indicating its "intent to increase the stringency of existing energy efficiency standards and update the testing standards for five major home appliances: refrigerators, refrigerator-freezers, freezers, dishwashers, clothes washers and clothes dryers, with the intent to align these requirements with the outcomes of the United States (U.S.) Department of Energy rule-making activities currently underway and to have these requirements come into effect in 2024."

Stakeholders will have upcoming opportunities to provide input into the governor-in-council amendments in 2024 when they are published in the *Canada Gazette*, Part I. However, as the contemplated Ministerial regulatory amendments are more administrative, NRCan expects to proceed directly to *Canada Gazette*, Part II with those amendments.

— **Publication of Landfill Methane Amendment Regulations:** Environment and Climate Change Canada had invited interested parties to provide feedback on the **proposed regulatory framework in respect of landfill methane regulations** until May 19, 2023. The next steps of this consultation process will involve the publication of proposed regulations in the *Canada Gazette* in 2024 for a 60-day public comment period, followed by the publication of the final regulations later in 2024.

ABORIGINAL LAW

Authors: Bryn Gray, Daphne Rodzinyak, Heather Maki and Dustin Seguin



ABORIGINAL LAW

There were several developments in Aboriginal law and policy in 2023, which are relevant for power project development and the energy sector in Canada. This includes a successful misfeasance claim by a proponent against a provincial government that denied permits for a hydroelectric project and clarifications in the law relating to: (i) the legal effect of B.C.'s UNDRIP legislation; (ii) the threshold to trigger the duty to consult; (iii) and the test for Aboriginal title to submerged lands. It also includes significant provincial-First Nations agreements that will impact development in B.C. and other significant cases that will be important to follow as they proceed through the courts.

PROPONENT RECOVERS MILLIONS IN DAMAGES FOR MISFEASANCE IN DENYING PERMITS

The Supreme Court of British Columbia **recently awarded** a hydroelectric project proponent C$10.125 million in damages for a lost business opportunity after finding the B.C. government liable for the tort of misfeasance in public office relating to the denial of project permits opposed by a First Nation. The permits were for a run of river project near Squamish, B.C. and were opposed by the Squamish Nation (SN) based on alleged impacts to certain cultural sites established by a **Land Use Agreement** entered into between the Province and the SN. The Court found misfeasance — which is a misuse of power by a government office holder — after concluding that an Assistant Deputy Minister had improperly intervened to ensure the permits were denied.

By way of background, Greengen Holdings Ltd. (Greengen) applied for permits to the Ministry of Agriculture and Lands and the Ministry of the Environment for land tenure over Crown land pursuant to the ***Land Act*** and a water licence pursuant to the ***Water Protection Act*** (collectively, the Permits). The Permits were subsequently denied and Greengen claimed that the denial of the permits was based, not on the reasons set out in the decision letters, but on collateral political purposes related to the province's relationship with the SN.

The tort of misfeasance may be made out by proving one of two alternative bases of liability: (i) Category A involves conduct specifically intended to injure a person or class of persons; or (ii) Category B involves a public officer who acts with knowledge both that they have no power to do the act complained of (in other words, the act is unlawful) and that the act is likely to injure the plaintiff. In this case, Greengen advanced its claim under Category B.

The court concluded that the provincial representatives knew that denying the Permits would cause Greengen harm and found that the denial of the Permits was unlawful because the evidence demonstrated that the statutory decision-makers were prepared to approve the permits (and had concluded that consultation had been sufficient) but the permits were subsequently denied at the direction of an Assistant Deputy Minister, which fettered their decision making for improper purposes. The court found that the Assistant Deputy Minister had communicated the denial of the Permits to the proponent in November 2008 before the statutory decision-makers had even made the denial decisions (which were communicated in writing in August 2009). The court concluded that the Assistant Deputy Minister either made the decision himself or passed on a decision made by others that the project would not be allowed to proceed without the agreement of the SN and that this decision was made to appease the First Nation. Greengen was awarded C$10.125 million as a result of a lost business opportunity.

While the outcome of this decision was based on the specific facts, it is an important reminder to governments that applications for permits need to be considered on their merits by the appropriate statutory decision-makers in a procedurally fair way and that a proponent may have a remedy if a denial of a permit is influenced by other government officials for improper considerations.

SUPREME COURT OF B.C. CONFIRMS B.C. LEGISLATION DID NOT IMPLEMENT UNDRIP

In *Gitxaala v. British Columbia (Chief Gold Commissioner)*, **2023 B.C.SC 1680**, the first decision to interpret the B.C. ***Declaration on the Rights of Indigenous Peoples Act*** (DRIPA), the Supreme Court of British Columbia ruled that this legislation did not implement the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) into the domestic law of B.C. and did not create justiciable rights. However, the court concluded that UNDRIP could be used as an interpretive aid. For further background on DRIPA, see **British Columbia Regional Overview — Involvement of Indigenous Peoples**.

This case involved a challenge of the online registry system used in B.C. to stake mineral claims. Under this system, a 'free miner' is able to register a mineral claim over Crown land and the holder of such claims are granted various rights, including the ability to explore the claim area in search of minerals (with further approvals required for any extraction). There is no consultation required with Indigenous groups before claims are registered and consultation only occurs at later permitting stages. The Gitxaala Nation challenged the mineral tenure system, seeking declarations that it breached the duty to consult and it was inconsistent with the rights recognized in both DRIPA and UNDRIP.

The court found that the duty to consult was triggered by the current system of issuance of mineral claims due to potential adverse impacts on asserted or established Aboriginal rights. It issued a declaration that the province owes a duty to consult but suspended the implementation of that declaration for 18 months to provide for the development of a regime that allows for consultation.

With respect to the Gitxaala Nation's claim for a declaration that the current process for granting mineral titles is inconsistent with UNDRIP, the court concluded that, correctly and purposively interpreted, DRIPA does not implement UNDRIP in domestic law. Instead, DRIPA "contemplates a process wherein the province 'in consultation and co-operation with the Indigenous Peoples in British Columbia' will prepare, and then carry out, an action plan to address the objectives of UNDRIP." As a result, UNDRIP remains a non-binding international instrument.

Further, the court concluded that s. 3 of DRIPA does not create any justiciable rights and therefore the court could not intervene to determine whether provincial laws are "consistent" with UNDRIP. The court concluded that s. 3 allows for Indigenous Peoples of B.C., instead of the

courts, to be involved in the determination of whether the province's laws are consistent with UNDRIP. Notably, the court left open the possibility that a failure of the B.C. Crown to consult and co-operate with the Indigenous Peoples of B.C. in accordance with s. 3 could constitute a justiciable breach of Crown obligations, but such question did not arise and will be for a future court to decide.

This decision is consistent with statements made by the B.C. government at the time the UNDRIP legislation was enacted. The findings relating to UNDRIP are not binding with respect to the federal and Northwest Territories legislation but likely to be highly persuasive. The decision is currently under appeal.

DISMISSAL OF ABORIGINAL TITLE CLAIM TO LAKE BED

Earlier this year, the Ontario Court of Appeal largely upheld a lower court dismissal of an Aboriginal title claim to a large portion of the lake bed of Lake Huron and Georgian Bay. **This case** confirmed that the test for Aboriginal title, as set forth in *Tsihqot'in v. British Columbia*, **2014 SCC 44**, applies to title claims to submerged lands without modification and will have implications for other Aboriginal title claims to submerged lands.

By way of background, the Chippewas of Nawash Unceded First Nation and Saugeen First Nation (collectively, the SON) commenced two claims against Canada and Ontario seeking: (i) a declaration of Aboriginal title to part of the lake bed of Lake Huron and Georgian Bay; and (ii) declaratory relief and damages relating to an alleged breach of a promise made by the Crown in Treaty 45½ to protect the Bruce Peninsula. The trial judge dismissed the SON's Aboriginal title and treaty fiduciary duty claim but held that the pre-Confederation Crown breached the honour of the Crown in fulfilling Treaty 45½ and in some of the Crown's conduct relating to the negotiation of Treaty 72.

In dismissing the SON's title claim, the trial judge found that the SON had not established sufficient and exclusive use of the lake bed and had minimal use of the lake bed at the time of the assertion of sovereignty. Further, the trial judge held that the public right of navigation is "paramount" and the geographic location of the SON's claim area within the well-travelled waters of the Great Lakes conflicted with the exclusive nature of Aboriginal title. The SON were notably claiming that title would give them the right to control every aspect of occupation of the water and that any incursion on that right (including defence, recreation, commerce, navigation etc.) would need to comply with s. 35 of the *Constitution Act, 1982*.

The SON asserted that the trial judge made numerous errors in determining the title issue, including in setting too high of a threshold to determine various aspects of the title test in light of the submerged nature of the lands. The Court of Appeal dismissed the various errors asserted by the SON and found, among other things, that the trial judge gave sufficient weight to the Aboriginal perspective; appropriately took into account the submerged nature of the land claimed; and did not set too high a threshold for determining control by SON of the claimed land. The Court of Appeal held that it was not possible to determine whether the public right of navigation conflicted with Aboriginal title until the extent of Aboriginal title in any part of the submerged lands, if any, is determined.

Although the Court of Appeal did not identify any error in the trial judge's approach to the determination of Aboriginal title, it held that the SON should not have to bring a new proceeding to determine if they could establish title to a smaller portion of the claim area. It ordered a further hearing by the trial judge to determine whether Aboriginal title can be established to a more limited area, which contemplates further evidence and pleadings. Leave to appeal to the Supreme Court of Canada has been sought by the SON and Ontario.

UNSUBSTANTIAL OR NEGLIGIBLE ADVERSE IMPACTS INSUFFICIENT TO TRIGGER THE DUTY TO CONSULT

In the recent decision, *Waterhen Lake First Nation v. Saskatchewan (Minister of Parks, Culture and Sport)*, **2023 SKKB 230**, the Saskatchewan Court of King's Bench found that "unsubstantial" or "negligible" adverse impacts to Aboriginal treaty rights resulting from Crown conduct did not trigger the duty to consult. The court found that the provincial Crown had no duty to consult Waterhen Lake First Nation (WLFN) prior to approving a work permit for an inland marina on Waterhen Lake in Meadow Lake Provincial Park because WLFN failed to establish that the impacts were appreciable or "beyond insignificant and negligible."

The evidence in this case established that the construction of the inland marina would have certain impacts to WLFN's treaty harvesting right, including closing a trail that would require a "modest detour" to access hunting and trapping grounds and the excavation of 200 feet by 250 feet, which could result in the loss of some plants gathered by the WLFN. The court acknowledged this loss but found it to be "very modest" once put within the context of a 450-km shoreline that was accessible to WLFN members in which plants could still be gathered, and WLFN members did not have to travel further distance or undergo difficulty or increased time to gather.

The court's conclusion was based on a review of the Supreme Court of Canada decisions of *Mikisew Cree First Nation v. Canada (Minister of Canadian Heritage)*, **2005 SCC 69**, and *Rio Tinto Alcan Inc v. Carrier Sekani Tribal Council*, **2010 SCC 43**, the Federal Court decision of *Brokenhead Ojibway First Nation v. Canada (Attorney General)*, **2009 FC 484**, as well as the B.C. Court of Appeal decision, *R v. Douglas*, **2007 B.C.CA 265**. This decision underscores the need for appreciable and non-negligible impacts to trigger the duty to consult although governments take varying approaches to assessing this issue and may still engage for relationship, policy, or risk mitigation reasons.

UNDRIP UPDATES

2023-2028 Action Plan

In June 2023, the government of Canada released its **UN Declaration Act Action Plan (Action Plan)**, pursuant to the federal ***UNDRIP Act***. This plan sets out 181 specific measures and adopts a distinction-based approach in organizing the measures into priorities that are shared among First Nations, Inuit, Métis, modern treaty and self-governing nations and diversity groups. The plan is ambitious and many of the commitments are broadly worded and open to varying interpretation.

The plan includes measures that have important implications regarding Indigenous consultation and considerations for project development, including but not limited to commitments to:

i. develop new guidance on engaging with Indigenous Peoples on natural resources projects that aligns with UNDRIP and that "provides practical recommendations for successful free, prior and informed consent implementation;"

ii. pursue amendments to fisheries legislation, regulation or policies to support the meaningful implementation and exercise of Indigenous fishing rights;

iii. create measures that could enable Indigenous governments and organizations to exercise federal regulatory authority in respect of matters regulated by the Canada Energy Regulator;

iv. ensure the Impact Assessment Agency carries out impact assessments in a manner that aligns with UNDRIP, including an emphasis on free, prior and informed consent;

v. establish an independent Indigenous rights monitoring and oversight mechanism for dispute and conflict resolution and remedies for infringements of individual and collective rights; and

vi. develop and implement measures to increase economic participation of Indigenous Peoples and communities in natural resource development.

There is a broad range of ways in which these commitments could be implemented and it remains to be seen how and when these commitments will be implemented. This work is expected to take considerable time and the federal government is required under the *UNDRIP Act* to annually report on their progress in implementing the Action Plan.

Consent Decision-Making Agreement

On November 1, 2023, the province of B.C. entered into the second **consent decision-making agreement** with the Tahltan Central Government under s. 7 of **DRIPA**. Section 7 of DRIPA provides for the negotiation of agreements with Indigenous governing bodies to jointly exercise statutory powers or to require the consent of the Indigenous

governing body before the exercise of a statutory power of decision. This second agreement relates to proposed amendments to the environmental assessment certificate for the Red Chris mine project. The agreement sets out a process for the Tahltan to both participate in the provincial environmental assessment process and conduct its own risk assessment of certain proposed amendments to the Red Chris mine project and requires the seeking of the Tahltan's consent at various junctures.

To date, the only consent decision-making agreements have been with the Tahltan Central Government in northern B.C. and for mining projects.

UNDRIP Legislation in the Northwest Territories

On October 10, 2023, the government of the Northwest Territories (GNWT) enacted **Bill 85**, the *United Nations Declaration on the Rights of Indigenous Peoples Implementation Act* (the *UNDRIP Implementation Act*). In much of the same way as the province of B.C. **enacted** DRIPA, the ***UNDRIP Implementation Act*** provides a framework to address the objectives of UNDRIP and further reconciliation by the GNWT.

The purposes of the *UNDRIP Implementation Act* are to affirm UNDRIP as a universal human rights instrument with application to Indigenous Peoples and laws of the Northwest Territories, to provide a framework for the implementation of UNDRIP, and to affirm the roles and responsibilities of Indigenous governments and organizations in the implementation of the UNDRIP.

The legislation is similar to the legislation enacted by the governments of B.C. and Canada in that it provides a framework to implement UNDRIP over time and it does not give immediate effect to UNDRIP. There are some differences in the legislation including that any Minister introducing legislation is required before second reading to table a Statement of Consistency prepared by the Attorney General regarding whether the bill is consistent with UNDRIP and s. 35 of the *Constitution Act*, *1982*. The legislation also requires a five-year review of the legislation by an independent person or entity appointed by the joint Action Plan Committee.

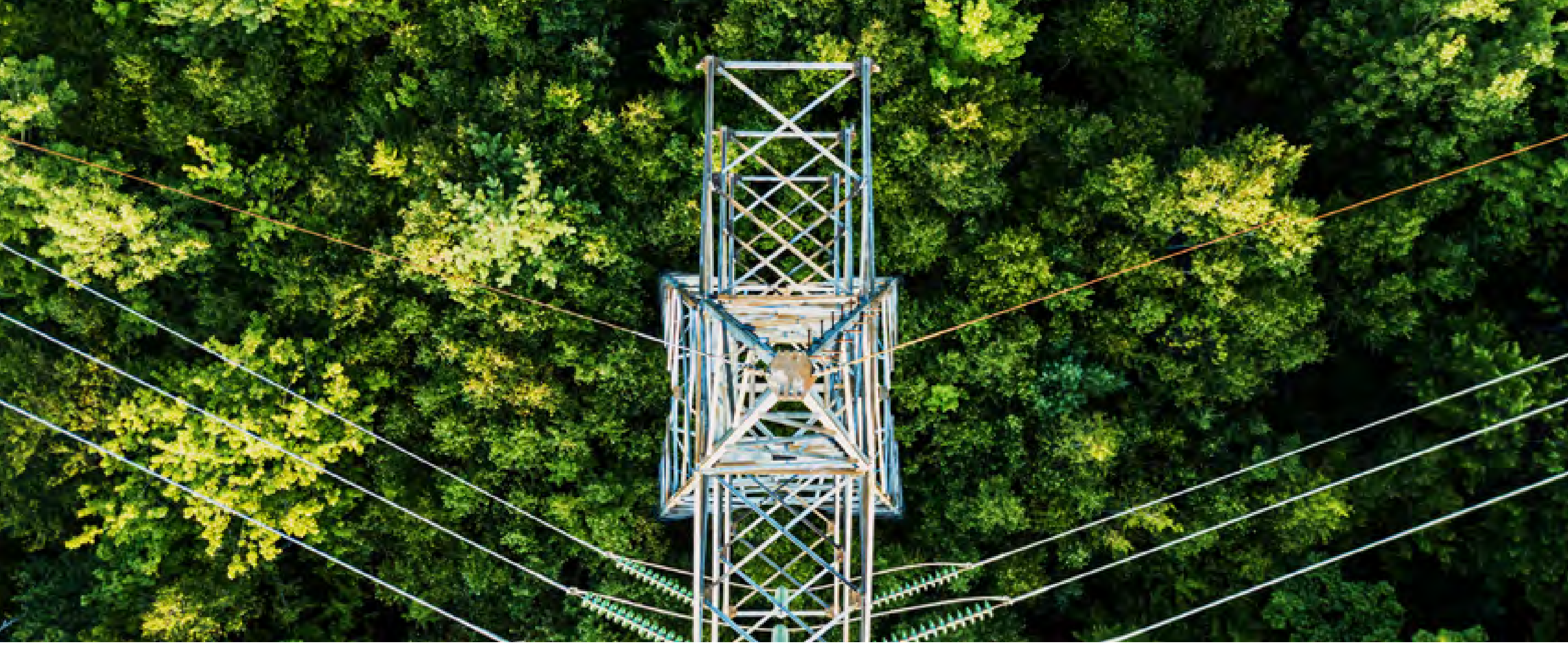
BLUEBERRY RIVER FIRST NATION IMPLEMENTATION AGREEMENT

In response to the decision of *Yahey v. British Columbia*, **2021 B.C.SC 1287** (discussed further in **Power Perspectives 2022**), the B.C. government and Blueberry River First Nation (BRFN) entered into the **Blueberry River First Nation Implementation Agreement**. In *Yahey*, the Supreme Court of B.C. found that the provincial government had unjustifiably infringed the treaty rights of BRFN through the cumulative effects of provincially authorized industrial development over the last several decades. As a result, the B.C. government entered into an interim agreement with BRFN in October 2021, and the final agreement on January 18, 2023, to negotiate a collaborative approach to land management and natural resource development that protects the BRFN's treaty rights.

The agreement sets out a number of measures including but not limited to: (i) an ecosystem-based management approach for future land-use planning in BRFN's most culturally important areas; (ii) more than 650,000 hectares of land protection from new petroleum and natural gas (PNG) and forestry activities; (iii) limits on new PNG development and a new planning regime for future oil and gas activities; (iv) protections for old forest and trap lines during and through planning; (v) wildlife co-management efforts; and (vi) a C$200-million restoration fund to support the healing of the land from industrial disturbance.

While the agreement is largely focused on PNG and forestry activity, this agreement will have significant impacts on the province's approach to assessing and managing cumulative effects and land-use planning in Treaty 8, including with respect to power projects, and may lead to requests to expand these arrangements to other areas of B.C. The agreement provides that, for all other natural resource applications not governed by a land-use plan, the province and BRFN will work together to establish a referral and consultation process acceptable to the parties and in accordance with Article 8 of the agreement. Under the agreement's provision for land-use planning, the province and BRFN are also to determine together where certain activities can occur, and under what requirements, and where they will be avoided in the future. The province and BRFN are also undertaking to co-ordinate wildlife management and habitat management, which may have additional impacts on project development. Electricity transmission projects are likely to give rise to more cumulative impact concerns in comparison to electricity generation projects.

B.C. also subsequently **announced** an agreement with four other Treaty 8 First Nations — Fort Nelson, Saulteau, Halfway River and Doig River First Nations — on "a collaborative approach to land and resource planning." The province is in similar negotiations with the remaining Treaty 8 First Nations in B.C. — McLeod Lake Indian Band, Prophet River First Nation and West Moberly First Nations — and is expected to reach similar agreements with these First Nations.



At the same time, two Treaty 8 First Nations with overlapping territories have sought judicial reviews of the government's decision to implement the BRFN Implementation Agreement on the basis that they were not adequately consulted about measures in the agreement that could impact their treaty rights, including how the agreement would affect B.C.'s exercise of statutory powers respecting industrial activities in the overlapping claim areas. The First Nations assert that the agreement is severely restricting their ability to participate meaningfully in the management of industrial activities in the portion of their territories that overlap with the BRFN claim area.

CASES TO WATCH

Co-Jurisdiction Between First Nations and Government

In May 2023, certain Treaty 9 First Nations released a **draft Statement of Claim** against Canada and Ontario that seeks various declarations including that they hold treaty rights of "decision-making governance authority over land." Treaty 9, which includes similar land surrender language as the numbered treaties across Canada, covers a very large portion of northern Ontario to Hudson Bay and James Bay and includes the Ring of Fire. The First Nations assert that they did not surrender their jurisdiction relating to land, including submerged lands and natural resources, and that Treaty 9 intended for a sharing of jurisdiction with the Crown. The Treaty 9 First Nations are seeking equitable compensation in the amount of C$95 billion from Canada and Ontario for the breach of the Treaty and duties of the Crown.

This case is at a very early stage but will be an important case to watch given its potential implications for projects in Treaty 9 territory.

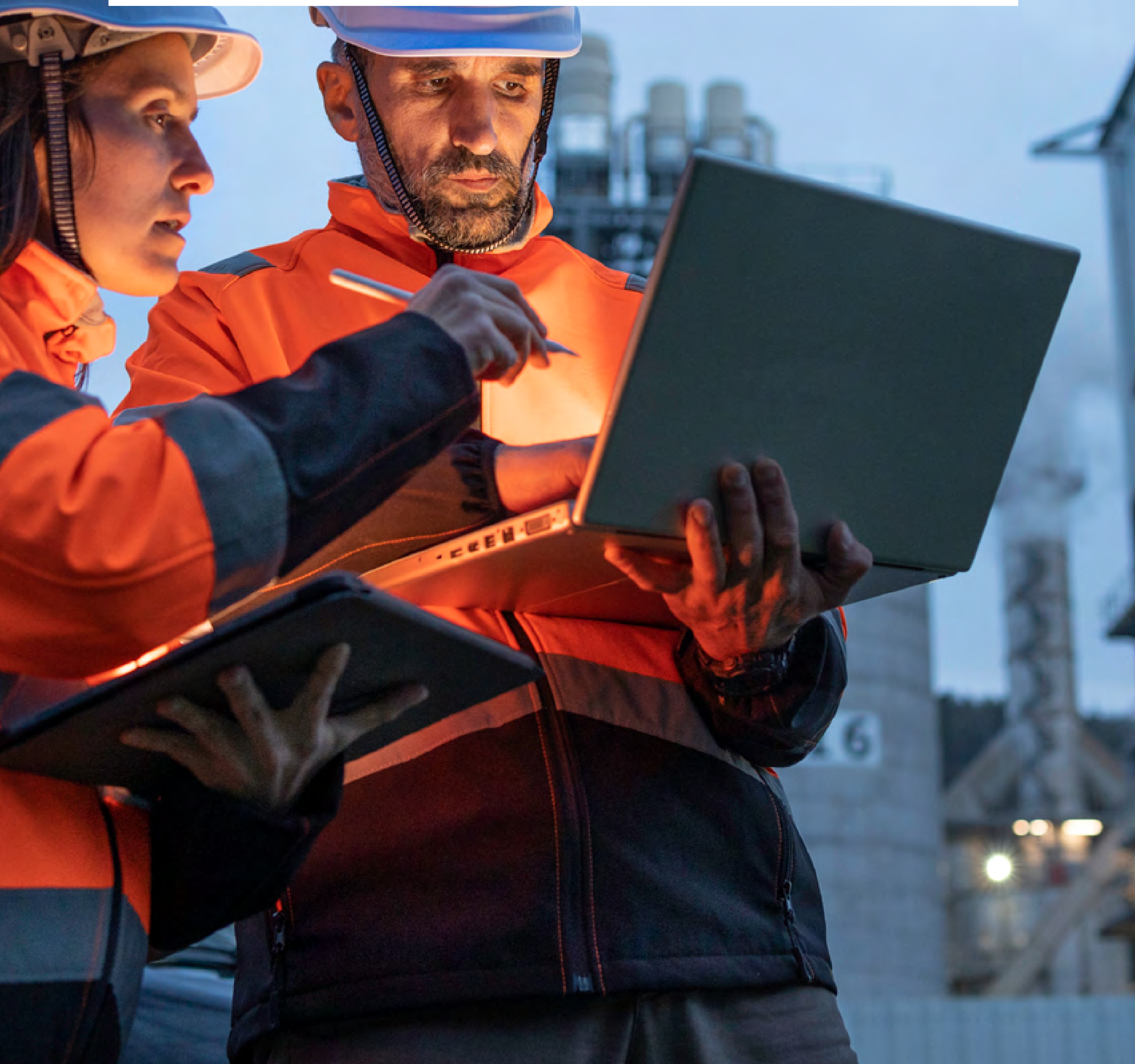
Aboriginal Title Trial Decision in B.C.

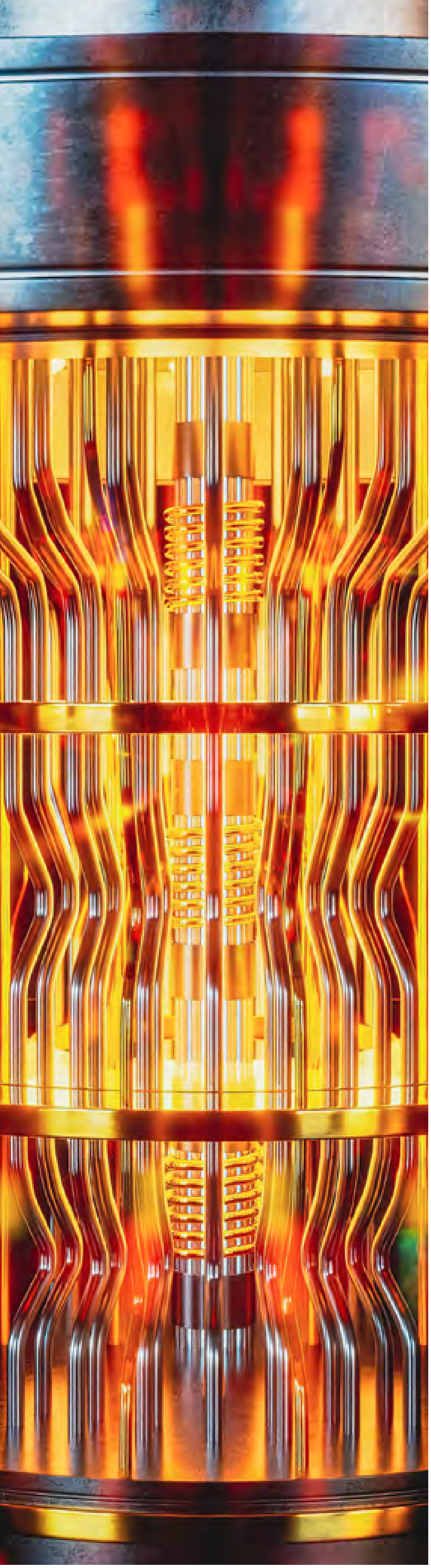
The Supreme Court of B.C. is likely to release a decision this year in an Aboriginal title claim to lands in the City of Richmond, B.C. The alleged title lands are Crown lands owned by the City of Richmond and the Vancouver Fraser Port Authority (as agent of Canada), as well as private lands owned by numerous private parties holding fee simple titles derived from colonial and provincial grants. The Cowichan Tribes are seeking to recover the Crown lands but have **previously clarified** to the Supreme Court of B.C. that they are not seeking a declaration of invalidity or defectiveness to the fee simple interests in the private claim area, nor do they claim they are entitled to possession of such land as against any private land owner. That said, a finding of title does not preclude them from seeking dispossession in the future and the declarations that they are seeking relating to infringement could affect future use of privately owned land if successful.

This case is one of the few Aboriginal title cases that have gone to trial and is unique from the other Aboriginal title claim trials to date that have been focused on Crown land in less developed areas. The private land issues and the consideration of the bona fide purchaser for value defence in the context of municipal lands could have implications for other current and future Aboriginal title claims to privately owned land in Canada. The trial was completed in fall 2023 and a decision is expected shortly. Any decision will likely be appealed and, if so, it will be several years before this issue is resolved.

NUCLEAR AND SMALL MODULAR REACTORS

Authors: Kaelyn Macaulay, Stephen Furlan, Gaëtan Thomas and Audrey Bouffard-Nesbitt





National Power Publication — The Beginning of a Nuclear Renaissance?

"We have not seen a model where we can get to net-zero emissions by 2050 without nuclear."
— Minister of Natural Resources Seamus O'Regan, **2020**.

Last year's publication and previous **blog posts** have highlighted important developments surrounding Small Modular Reactors (SMRs) in Canada. While SMR deployment is still making steady headway, the broader nuclear industry has also been gaining momentum this year. The tides of public opinion and political favour have significantly shifted toward large nuclear projects in the last two to three years. In 2023, the Canadian nuclear industry was solidified as a crucial component in Canada's plan to lower carbon emissions. The future of nuclear production looks bright in light of this year's announcements and achievements, which include increased funding opportunities, project expansions, new partnerships, regulatory amendments and Indigenous collaboration.

FEDERAL UPDATES

Federal Budget

Perhaps one of the biggest nuclear news developments was the release of the federal government's 2023 budget. The budget squarely recognizes nuclear power, SMRs in particular, as a necessary tool in making carbon neutrality a reality. It was previously unclear whether large nuclear generation would be included in the federal government's categorization of clean energy technology, but budget 2023 dispelled this uncertainty.

Nuclear projects of all sizes will be eligible for the new investment tax credits proposed in the 2023 budget. We explored the 2023 budget's highlights related to SMRs, including the new tax credits, in more detail **earlier this year**. The Canada Infrastructure Bank (CIB), which supported the Darlington SMR Project with a C$970-million loan commitment in 2022, received an additional C$20-billion in funding under the 2023 budget a large component of this allocation to be deployed to clean energy projects, including nuclear projects. We also saw in 2023 the launch of the Critical Minerals Infrastructure Fund by the government of Canada, with uranium being classified as a critical mineral. Given the high barrier of upfront financing and delayed returns for nuclear projects, these increased financing tools will be an important stimulus for the development of new projects as well as the expansion of existing ones.

Impact Assessment Act

On October 13, 2023, the Supreme Court of Canada **struck down** overly broad provisions of the federal *Impact Assessment Act*, finding that the federal parliament had overstepped the division of constitutional competence. Despite the recent emphasis on reducing regulatory hurdles for new nuclear projects, this decision has added an element of uncertainty to the future of federal regulation of Canadian energy initiatives. To minimize this uncertainty, the Canadian government released an **interim guidance framework** that details how the government will treat project assessments until it can amend and reinstate the *Impact Assessment Act*. Projects that are currently being assessed will receive an opinion on whether they impact areas of federal jurisdiction, however no new designation requests will be processed until the amended legislation comes into force. Unless new legislation is introduced quickly, development of large industrial and infrastructure projects, including nuclear projects, in all provinces may be delayed.

PROVINCIAL UPDATES

Ontario

Ontario's nuclear industry celebrated several major accomplishments in 2023. The **major component replacement of unit 6** at the Bruce Power site was completed on budget and ahead of schedule, even in the midst of the COVID-19 pandemic, an outstanding accomplishment. The upgrade will extend the reactor's life by 40 years, and Bruce Power plans to refurbish five more units in the next decade. This feat signals that key Canadian nuclear power players can handle significant project upgrades efficiently and cost-effectively. Bruce Power's success is particularly significant because it privately funded the C$13-billion upgrade, thus providing a model to encourage future private investment into Canada's nuclear sector.

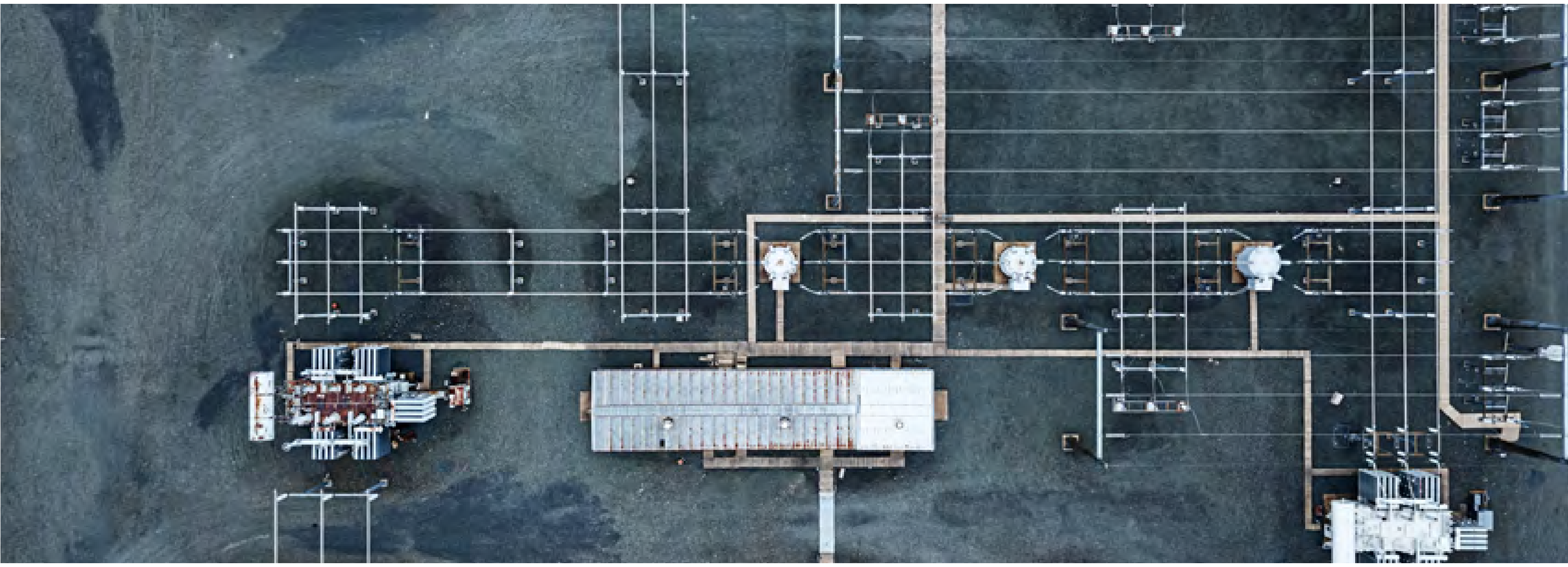
To better support capital-intensive projects which rely on innovative financing solutions, Ontario announced that it will be launching the **Ontario Infrastructure Bank** (OIB). The OIB's role will be to enable institutional investors such as public-sector pension plans and Indigenous communities to participate in large-scale infrastructure projects that align with the Ontario public interest. This initiative was announced in November and more details around the OIB's selection criteria and available funding are sure to follow. Given the prominence of nuclear power generation and the nuclear industry in Ontario and the supportive stance of the provincial government to the industry, we speculate that nuclear technology will likely be within the OIB's mandate.

The government of Ontario also announced in July 2023 that it is exploring an **expansion of the Bruce Power site**. The proposed expansion would add 4,800 MW of capacity to the facility, which already provides approximately 30% of the province's electricity. Shortly after the Bruce Power expansion announcement, Ontario Power Generation announced its **plan to add three SMRs** to its Darlington facility. The SMRs are expected to become operational between 2034 and 2036, allowing the developers time to implement learning outcomes from concurrent project developments. The atmosphere of collaboration and partnership is an important element of the Canadian nuclear industry and will be crucial in minimizing the risk of delay while maintaining the highest possible safety standards.

Saskatchewan

Partnerships between nuclear stakeholders often extend across provincial lines, benefiting Canadians across the country. In 2023, Saskatchewan's Cameco and Ontario's Bruce Power entered into an **extension of the agreement** under which Cameco will continue to exclusively supply Bruce Power's uranium and fuel requirements until 2040. This will generate an estimated C$2.8 billion in additional business between the two companies and further strengthen Canada's nuclear supply chain. In 2023, Cameco also secured agreements to supply uranium to state-owned nuclear corporations in **China** and **Ukraine**.

Saskatchewan is also forming new partnerships to progress its implementation of SMRs in the province.



In November 2023, SaskPower **entered into a master services agreement** with Ontario Power Generation and Laurentis Energy Partners. The agreement provides a five-year plan to co-ordinate the development of a Canadian fleet of SMRs, with two regions in Saskatchewan identified as potential facility sites. SMRs are particularly valuable energy sources for small, rural communities, which typically rely on transported fossil fuels, such as diesel, for their power supply. Saskatchewan is a logical candidate for SMR deployment with a large uranium mining industry, a supportive provincial government and many geographically disbursed rural communities.

Alberta

Nuclear development in Alberta will likely lag behind that of other provinces so as to benefit from their knowledge and experiences. Nevertheless, regulatory changes are being put into motion so that when Alberta is ready to pursue nuclear initiatives, the process will be both robust and expedient. The provincial government has already called for the **development of a specific regulatory framework for SMRs**, and has highlighted the key role that SMRs may play in reducing emissions from oilsands production. Cenovus Energy is conducting a series of studies over four years on the viability of SMR deployment in the oilsands, which will be partially funded by a **C$7-million investment** from the Alberta government. Alberta is uniquely placed to take advantage of this developing sector due to its strong history of energy investment and high rates of public support for nuclear technology.

In tandem with the proposed regulatory updates, Albertan entities are positioning themselves to benefit from the growing momentum in nuclear development. The Invest Alberta Corporation has entered into memoranda of understanding with **X-Energy Canada** and **ARC Clean Technology Canada** (ARC) to explore options for SMR development and implementation. The government of Alberta has similarly joined with the **Korea Atomic Energy Research Institute** to consider deploying Korean SMR models in Alberta. The province has also committed to investing C$225 million in the development of clean technology adoption, although it does not explicitly state whether nuclear energy will be included in this initiative.

New Brunswick

NB Power has recognized the utility of SMRs in decarbonizing New Brunswick's electricity sector by including an SMR rollout scenario in its **2023 Integrated Resource Plan**. The government of New Brunswick supported this initiative in its 2022/23 mandate letter to NB Power, which called upon NB Power to support SMR advancement in the province and pursue federal funding for additional reactors at the Point Lepreau Nuclear Generating Station. NB Power has since **committed to adding 600 MW** of SMR-generated power, effectively doubling Point Lepreau's baseload generation. To give a sense of proportion, Point Lepreau supplies approximately 35% of New Brunswick's current electricity needs and without the additional rollout of SMRs, NB Power predicts that the province would have to increase its wind and solar generation more than tenfold.

In June 2023, NB Power **submitted an application** to the Canadian Nuclear Safety Commission for a licence to prepare the Point Lepreau site for the deployment of one ARC-100 SMR, which is expected to be the first deployment of an on-grid advanced SMR facility in Canada. An environmental impact assessment application under provincial law was also submitted in June 2023 for the project. These regulatory filings represent important steps toward SMR implementation in the province and a **November 28, 2023** memorandum of understanding among NB Power, ARC and Korea Hydro and Nuclear Power Co., Ltd. represents an opportunity to bring the ARC-100 to a global market.

The Belledune Port Authority is another candidate for SMR development in the province, having **previously announced** that it is considering deploying the ARC-100 SMR to support hydrogen production and other industries in northern New Brunswick.

Indigenous Engagement

Industry stakeholders recognize that Indigenous participation in clean energy partnerships will be vital to increasing public acceptance of nuclear project proposals. Such collaborative efforts are already well underway. In September, the North Shore Mi'kmaq Tribal Council **announced a C$3-million investment** in SMR technology in New Brunswick. The Council's member communities stand to directly benefit from the expected deployment of SMR reactors within the next five to 10 years. Earlier in 2023, the Algonquins of Pikwakanagan First Nation **signed an agreement** to establish a framework for ongoing collaboration with Canadian Nuclear Laboratories and Atomic Energy of Canada Ltd. (AECL). The agreement focuses on a proposed low-level radioactive waste facility at AECL's Chalk River site. These collaborative efforts support part (i) of the **Truth and Reconciliation Commission's 92nd Call to Action** regarding reconciliation in the corporate sector.

These examples of meaningful strategic and financial engagement with Indigenous Peoples demonstrate the unexpected potential for reconciliation efforts in the growing field of nuclear power.

International Considerations

Developments abroad have brought a new focus on the security afforded by local, independent energy supply chains. The Russia-Ukraine war has had a significant impact on the supply of energy in Europe, markedly increasing energy prices around the world. The recent instability surrounding fossil fuel supply and demand caused European markets to drastically **increase their importation of clean energy products**. Canada's nuclear industry benefits from a nearly 100% Canadian-sourced supply chain, significantly reducing the risk of interference from foreign entities. Our existing trade partnerships are also relatively stable and low-risk; U.S. President Joe Biden and Prime Minister Justin Trudeau **issued a joint statement** on the next steps in pursuing a nuclear partnership. Furthermore, Canada has formed an **alliance with other G7 countries** who collectively represent 50% of the world's uranium conversion and enrichment capacity (known as the "Sapporo 5") that intend to provide alternatives to Russia in the global supply chain for nuclear power. In September 2023, the Canadian Minister of Energy and Natural Resources announced that Canada will **provide C$3 billion in export financing** to Romania's nuclear operator, Nuclearelectrica, to build two Canada deuterium uranium (CANDU) nuclear reactors at the Cernavoda nuclear plant. These opportunities for international collaboration strengthen Canada's bilateral economic relationships and position Canada as a potential global leader in the development of nuclear energy.

It's worth noting that 2023 concluded with a huge win for nuclear on the international stage at the United Nation's 28th Climate Change Conference of Parties (COP28) in Dubai. For the first time in the history of these conferences, nuclear energy was **officially recognized** among the zero-emissions and low-emissions technologies that could support deep, rapid and sustained reductions in greenhouse gas emissions. Two other historic announcements were made during meetings that took place on the sidelines of the COP28 negotiations. First, 22 countries, including Canada, issued a **declaration** to triple global nuclear energy capacity by the year 2050 to meet climate goals and energy needs. Subsequently, the Sapporo 5 **announced** plans to mobilize "at least US$4.2 billion in government and private investment in enrichment and conversion capacity over the next three years … with a view to further additional private sector finance, and invite all like-minded nations to join in securing the global uranium supply chain."

CONCLUSION

It's fair to say that 2023 was a renaissance year for the nuclear industry in Canada with major milestones of success, such as the early (and on-budget) completion of the Bruce Power refurbishment, and significant capital commitments by government, such as the federal government's investment tax credits. The impacts of the CIB's expanded role and the OIB's new mandate remain to be seen, but there is industry-wide optimism that their contributions will be significant. Success in the nuclear domain, particularly with cutting-edge modular nuclear technology, will require a combination of government capital support, private industry discipline and ingenuity, and a supportive regulatory environment. In 2023, Canada had significant achievements on all of these fronts.

TAX INCENTIVES FOR CLEAN ENERGY

Authors: Matthew Kraemer, Adam Unick and Micky Hoskin

Updates Regarding New Clean Economy Investment Tax Credits

Over the past few years, the federal government has introduced new investment tax credits to promote investment in clean technology in Canada. These tax credits are:

— the Clean Hydrogen Investment Tax Credit (CH Tax Credit);

— the Clean Technology Investment Tax Credit (CTI Tax Credit);

— the Clean Electricity Investment Tax Credit (CEI Tax Credit);

— the Investment Tax Credit for Carbon Capture, Utilization, and Storage (CCUS Tax Credit); and

— the Investment Tax Credit for Clean Technology Manufacturing (CTM Tax Credit).

In 2023, there were significant updates regarding these tax credits. The Federal Budget 2023 on March 28, 2023 introduced new investment tax credits, including the CEI Tax Credit, provided further detail on previously announced tax credits and proposed enhancements to other previously announced tax credits. On August 4, the federal government released a series of draft legislative proposals on various tax measures, including the CTI Tax Credit and the CCUS Tax Credit. Further, the August 4 draft legislation included provisions regarding the labour requirements (Labour Requirements) that must be satisfied to maximize the CH Tax Credit, CTI Tax Credit, CEI Tax Credit, and the CCUS Tax Credit. The 2023 Federal Fall Economic Statement (FES) provided additional details on design and implementation. On November 28, 2023, revised legislation, significantly departing from the draft legislation was tabled to, among other things, implement the CTI Tax Credit, the CCUS Tax Credit and the Labour Requirements.

Herein we provide a chronology and high-level overview of each of the clean economy tax credits and the Labour Requirements to date. More detailed information regarding the clean economy tax credits is available on the McCarthy Tétrault website.

CLEAN HYDROGEN INVESTMENT TAX CREDIT

The 2022 FES announced the federal government's intention to introduce the CH Tax Credit to encourage investment in clean hydrogen production that would reduce emissions of greenhouse gases. The 2023 FES indicated that the federal government intends to introduce legislation in Parliament in early 2024. Draft legislation was released on December 20, 2023 for public consultation.

The CH Tax Credit is a 15%, 25% or 40% refundable tax credit in respect of the cost of purchasing and installing eligible equipment for eligible projects that produce hydrogen from electrolysis or natural gas (so long as emissions are abated using carbon capture, utilization, and storage (CCUS)). The 2023 FES introduced eligibility for clean ammonia production equipment at the lowest credit rate of 15% and confirmed that the federal government will continue to review eligibility for other low-carbon hydrogen production pathways in the lead-up to Budget 2024.

To determine the applicable credit rate, projects will be required to assess the expected carbon intensity of the hydrogen that is produced (measured in kg of carbon dioxide equivalent per kg of hydrogen). As discussed below, if the taxpayer does not elect to satisfy the Labour Requirements, the amount of the CH Tax Credit could be reduced by 10%. Additionally, the credit may be subject to a clawback or recovery based on a comparison between the actual carbon intensity of the hydrogen produced by a project and the assessed carbon intensity. The 2023 FES proposed that this potential clawback or recovery occur pursuant to a one-time verification, based on a five-year compliance period. It also proposes allowing an acceptable margin of error between the actual carbon intensity of the produced hydrogen and the assessed carbon intensity. Eligible equipment that is required to convert clean hydrogen to clean ammonia will also be available for the CH Tax Credit at the lowest credit rate of 15%.

The CH Tax Credit will apply in respect of eligible equipment that is acquired and becomes available for use (in accordance with the available for use rules applicable to depreciable property) in an eligible project on or after Budget Day 2023. Budget 2023 proposes to phase out the CH Tax Credit gradually, with property that becomes available for use in 2034 eligible for one-half of the applicable credit and no credit available for property that becomes available for use after 2034.

CLEAN TECHNOLOGY INVESTMENT TAX CREDIT

Announced in the 2022 FES, the CTI Tax Credit is a 30% refundable tax credit applicable to investments in "clean technology property" (as defined in s. 127.45(1)). The stated purpose of the CTI Tax Credit is "to encourage the investment of capital in the adoption and operation of clean technology property in Canada." Draft legislation and revised draft legislation to implement the CTI Tax Credit was released on August 4, 2023. On November 28, 2023 legislation implementing the CTI Tax Credit was tabled in Parliament.

The 2023 FES expanded the property eligible for the CTI Tax Credit to support the generation of electricity, heat, or both electricity and heat (i.e., cogeneration), from waste biomass. The government indicated it intends to commence draft legislation consultations regarding this expanded eligibility to launch in summer 2024 and to introduce legislation in Parliament in fall 2024.

As discussed below, if a taxpayer does not elect to satisfy the Labour Requirements, the amount of the CTI Tax Credit could be reduced by 10%. The credit received by a taxable Canadian corporation may be subject to recapture where, within 10 calendars years of the acquisition of clean technology property that entitled the taxpayer to the tax credit, the property is: (i) converted to a "non-clean technology use;" (ii) exported from Canada; or (iii) disposed of. There is an exception to this recapture for taxable Canadian corporations where the property is disposed of pursuant to certain non-arm's length transfers.

There are various conditions within the definition of "clean technology property," including that the property be situated in Canada (which includes wind energy and kinetic energy conversion systems that are installed in the exclusive economic zone of Canada) and that the property be intended for use exclusively in Canada. The types of eligible property are described in part by reference to

the classes of property described in Schedule II to the regulations for capital cost allowance purposes. The Fall Economic Statement proposes to expand eligible property further to include systems that use “specified waste materials” solely to generate electricity, heat, or electricity and heat. As revised by the November tabled legislation, eligible property now includes equipment that is used exclusively to generate electrical or heat energy from geothermal energy for sale or use. Equipment that co-produces fossil fuel for sale is not eligible.

The CTI Tax Credit is limited to “qualifying taxpayers,” defined as taxable Canadian corporations or a mutual fund trust that is a “real estate investment trust” (as defined in s. 122.1(1)). Additionally, the tabled legislation includes a series of rules regarding the application of the CTI Tax Credit and CCUS Tax Credit to partnerships, enabling partners that are taxable Canadian corporations to claim their share of the CTI Tax Credit derived from expenditures made by the partnership to acquire clean technology property. Pursuant to new s. 127.47, the total tax credit amount that may be allocated to a limited partner is restricted to a reasonable proportion and may not exceed a partner’s at-risk amount in respect of the partnership. Additionally, the total clean economy tax credit allocated to a partner must be apportioned among each individual tax credit in a manner that reasonably corresponds to each credit.

The August 4 draft legislation included a rule in s. 127.45(9) that incorporated by reference existing ss. 127(8.1) to (8.5) with whatever modifications are necessary. Very generally, these provisions restrict a limited partner’s reasonable share of a partnership’s investment tax credit to the lesser of the partner’s at-risk amount and the amount of credit arising from the partner’s expenditure base. The aggregate amount by which the limited partners’ reasonable shares is reduced is deemed to be the reasonable share of the general partner or partners. The November 28 tabled legislation does not include a provision incorporating existing ss. 127(8.1) to (8.5) by reference. The tabled legislation included s. 127.47(3), which limits a limited partner’s share to be its at-risk amount but does not include any provision deeming the amount by which the limited partners’ shares are reduced to be the reasonable share of the general partner or partners. The exclusion of such a provision makes it questionable what happens to the excess of the credit and draws into question whether this amount can be the reasonable share of the general partner absent the deeming provision. We expect this change to cause significant disruption in the renewable energy infrastructure industry where limited partnerships are the preferred business structure and often there is debt at the partnership level.

Notably, the explanatory notes to the November 28 tabled legislation state that new s. 127.47 will also apply to the CH Tax Credit, CTM Tax Credit, and CEI Tax Credit when they are enacted.

The CTI Tax Credit will be applicable to investments in eligible property that are acquired and become available for use on or after Budget Day 2023 until December 31, 2033. The expanded CTI Tax Credit will only be available in respect of eligible waste biomass equipment that is acquired and becomes available for use on or after November 21, 2023. Pursuant to Budget 2023, the federal government proposes to phase out the CTI Tax Credit gradually, with property that becomes available for use in 2034 eligible for only a 15% credit and no credit available for property that becomes available for use after 2034.

For additional details, our review of the CTI Tax Credit as of September 18, 2023 can be found **here**. A blog describing the impact of the November 28 tabled legislation will follow.

CLEAN ELECTRICITY INVESTMENT TAX CREDIT

Budget 2023 announced the federal government's intention to introduce the CEI Tax Credit to support investments in clean electricity in Canada. The 2023 FES indicated that, for taxpayers except for publicly owned utilities, details will be published in early 2024 and draft legislation consultations will be launched in summer 2024. For publicly owned utilities, consultations with provinces and territories will be launched in 2024. For all taxpayers, the federal government plans to introduce legislation in Parliament in fall 2024.

The CEI Tax Credit is a 15% refundable investment tax credit that may be claimed by both taxable and tax-exempt entities. However, as discussed below, if the taxpayer does not elect to satisfy the Labour Requirements, the amount of the CEI Tax Credit could be reduced by 10%. The tax credit will be available in respect of costs incurred in refurbishing existing facilities as well as new projects. It will broadly apply to investments in non-emitting electricity generation systems, abated natural gas-fired electricity generation (subject to an emission intensity threshold), stationary electricity storage systems that do not use fossil fuels in operation and equipment for the transmission of electricity between provinces and territories. The 2023 FES expanded the property eligible for the tax credit to support the generation of electricity or both electricity and heat (i.e., cogeneration) from waste biomass.

There is significant (although not perfect) overlap between the types of property that qualify for the CEI Tax Credit and the CTI Tax Credit. It is not entirely apparent how the two credits will interact in the context of a partnership involving a taxable entity and a tax-exempt entity.

Budget 2023 included a statement that the CEI Tax Credit will only be available in respect of projects in jurisdictions in which a competent authority has committed that the federal funding will be used to lower electricity bills and committed to achieving a net-zero electricity sector by 2035 (Competent Authority Commitments Criteria). The 2023 FES indicated that the credit will treat publicly owned utilities and taxpayers other than publicly owned utilities differently. It is not clear at this point what the differences will be. Some are speculating that the Competent Authority Commitments Criteria will only apply in respect of publicly owned utilities.

The CEI Tax Credit will be available as of Budget Day 2024 in respect of projects that commenced construction on or after Budget Day 2023 and before 2034.

CARBON CAPTURE, UTILIZATION AND STORAGE INVESTMENT TAX CREDIT

Announced in Budget 2021, the CCUS Tax Credit is intended to encourage and support the investment of capital in the development and operation of carbon capture, transportation, utilization and storage capacity in Canada. Draft legislation was released in August 2022. In 2023, additional details regarding the tax credit were announced in Budget 2023, and the federal government released revised draft legislation on August 4. The 2023 FES indicated that legislation would be introduced in Parliament this fall and legislation implementing the proposal was included as part of the November 28 tabled legislation.

The rate of the CCUS Tax Credit depends on the type of expense and when the expense is incurred. Between January 1, 2022 and December 31, 2030, the rates will be 37.5%, 50% or 60%. Between January 1, 2031 and December 31, 2040, the rates will be one-half of the said rates. As discussed below, if the taxpayer does not elect to satisfy the Labour Requirements, the amount of the CCUS Tax Credit could be reduced by 10%. The credit may be clawed back through a recovery tax based on a comparison between the actual percentage of captured carbon stored or used in an eligible use and the projected percentages.

The CCUS Tax Credit, composed of the taxpayer's "cumulative CCUS development tax credit" and the taxpayer's "CCUS refurbishment tax credit," will be a refundable tax credit that is available in respect of "qualified CCUS expenditures." Qualified CCUS expenditures will include the cost of acquiring or installing eligible equipment used in a "qualified CCUS project" that results in carbon dioxide being used for an "eligible use." To be a qualified CCUS project, it must meet the following conditions, among others: the Minister of Energy and Natural Resources must issue a project evaluation for the project, the project must plan to operate for at least 20 years, and at least 10% of captured carbon must be expected to be stored or used in an eligible use. An "eligible use" of captured carbon is storing it in "dedicated geological storage" or using it in producing concrete in Canada or the United States using a "qualified concrete storage process." Among other things, dedicated geological storage must be in a "designated jurisdiction" as defined in s. 127.44(1).

The credit is only available for "qualifying taxpayers," which are taxable Canadian corporations. As previously noted, the tabled legislation includes rules that apply to partnerships, enabling partners that are taxable Canadian corporations to claim their reasonable share, limited to a limited partner's at-risk amount, of the CCUS Tax Credit derived from qualified CCUS expenditures made by the partnership to acquire property in respect of qualified CCUS projects.

The CCUS Tax Credit will apply to eligible expenses incurred on or after January 1, 2022 and before 2041.

Our detailed review of the CCUS Tax Credit as of November 17, 2023 can be found **here**. An updated detailed review will follow including consideration of the implications of the November 28 tabled legislation. Further, the federal government of Alberta announced on November 28, 2023 further efforts to incentivize the development and integration of CCUS infrastructure and technology in the province, discussed further below in this chapter.

CLEAN TECHNOLOGY MANUFACTURING INVESTMENT TAX CREDIT

Budget 2023 announced the federal government's intention to introduce the CTM Tax Credit for investments in clean technology manufacturing and processing or investments in critical mineral extraction and processing. The 2023 FES indicated the federal government's intent to introduce legislation in Parliament in early 2024. Draft legislation was released on December 20, 2023 for public consultation.

The CTM Tax Credit is a 30% refundable tax credit available in respect of certain depreciable property that is used all — or substantially all — for eligible activities. Eligible property would generally include machinery and equipment (including certain industrial vehicles) used in manufacturing, processing, or critical mineral extraction, as well as related control systems. Eligible activities will be, broadly, processing or recycling nuclear fuels and heavy water, extracting and certain processing activities related to critical minerals and manufacturing certain equipment and machinery. If the property becomes subject to a change in use, or is sold, within a certain (unspecified) period of time, a portion of the CTM Tax Credit will be clawed back.

The CTM Tax Credit will apply to property that is acquired and becomes available for use on or after January 1, 2024. Budget 2023 proposes a gradual phase out of the CTM Tax Credit: property that becomes available for use in 2032 will be eligible for a 20% tax credit, those in 2033 for a 10% tax credit, and those in 2034 for a 5% tax credit. There will be no credit for property that becomes available for use after 2034.

LABOUR REQUIREMENTS

The 2022 FES announced the intention to attach prevailing wage and apprenticeship requirements to certain tax credits, and Budget 2023 provided additional details. The August 4, 2023 draft legislation specified the Labour Requirements applicable to the CH Tax Credit, CTI Tax Credit, CEI Tax Credit, and the CCUS Tax Credit.

In brief, in order for a taxpayer to claim the maximum available specified tax credit, the taxpayer must elect to satisfy the Labour Requirements. If the taxpayer does not elect to satisfy the Labour Requirements, the applicable percentage of the relevant specified tax credit is reduced by 10%. If the taxpayer elects to satisfy the Labour Requirements but fails to do so, absent the Minister determining that the taxpayer knowingly or in circumstances amounting to gross negligence failed to meet the requirements, the credit is not reduced, but the taxpayer will be liable to certain additional taxes and penalties, which may be mitigated in certain circumstances by taking corrective measures.

The Labour Requirements apply in respect of each "covered worker" at a "designated work site" of an "incentive claimant" for an "installation taxation year" (as defined in s. 127.46(1)). Broadly, a "covered worker" is an individual who is engaged in the preparation or installation of specified property at a designated work site as an employee of an incentive claimant or of another engaged person or partnership (e.g., a contractor). A covered worker must be engaged in primarily manual or physical work or duties. A "designated work site" is where specified property is located and includes the site of a CCUS project. An "incentive claimant" means a person, or a partnership at least one member of which, plans to claim or has claimed a specified tax credit for a taxation year. Finally, an "installation taxation year" is a taxation year during which preparation or installation of specified property occurs.

The Labour Requirements have two prongs: a prevailing wage requirement and an apprenticeship requirement.

The prevailing wage requirement means that each "covered worker" at a "designated work site" of an "incentive claimant" for an "installation taxation year" must be compensated for their work under the terms of an "eligible collective agreement" or, if there is no eligible collective agreement, in an amount that is at least equal in value to the wages and benefits specified in the eligible collective agreement that most closely aligns with the covered worker's experience level, tasks and location, calculated on a per-hour or similar basis. If the relevant eligible collective agreement expires, the relevant wages and benefits stipulated under the agreement are to be indexed for inflation.

The "standard" requirement for the apprenticeship requirement is that the incentive claimant must make "reasonable efforts" to ensure that apprentices registered in a "Red Seal trade" work at least 10% of the total hours that are worked during each installation year by Red Seal workers at the incentive claimant's designated work site on the preparation or installation of specified property. However, if the number of apprentices employed at a designated work site is restricted — or a maximum ratio of apprentices to journeypersons is specified by an applicable collective agreement or by applicable law that prevents the standard requirement from being met — then the incentive claimant must make "reasonable efforts" to ensure that the highest possible percentage of the total labour hours performed during the installation year by Red Seal workers on the preparation or installation of specified property is performed by apprentices registered in a Red Seal trade within such restrictions or limitations. The November 28 tabled legislation specifies certain steps and conditions that, if taken, will deem an incentive claimant to have satisfied the "reasonable efforts" requirements.

Pursuant to the November tabled legislation, an incentive claimant is deemed to have satisfied the "reasonable efforts" requirement where, at least every four months, the claimant posts a job advertisement (meeting certain conditions) seeking apprentices, communicates with a trade union and at least one secondary or post-secondary school to facilitate the hiring of apprentice positions, and receives confirmation from the trade union that the union has provided as many apprentices as possible. Additionally, the claimant must review and consider all applications received in response to the advertisement and take reasonable steps to ensure that other applications are reviewed and considered, and attest that it has complied with the aforementioned requirements.

Our detailed review of the Labour Requirements can be found **here**. The more detailed review includes a description of the penalties and consequences of a claimant electing to satisfy the Labour Requirements but failing to do so. Please refer to the detailed review for a summary of these consequences. However, notably, the penalty for falling short of apprenticeship hours was reduced in the November 28 tabled legislation from C$100 per hour of shortfall (as specified in the August 4 draft legislation) to C$50 per hour of shortfall.

ALBERTA CARBON CAPTURE INCENTIVE PROGRAM

In addition to the federal CCUS Tax Credit, on November 28, 2023, the government of Alberta announced further efforts to incentivize the development and integration of CCUS infrastructure and technology in the province with the creation of the **Alberta Carbon Capture Incentive Program** (ACCIP) as part of Alberta's **Emissions Reduction and Energy Plan**. The ACCIP is intended to incentivize facilities to incorporate CCUS infrastructure and technology into their operations, including for oilsands, oil and gas production, enhanced oil recovery production, petrochemical, power generation, manufacturing, cement production and more. It is expected that between 2024 and 2035, the program will offer support in the aggregate amount of C$3.2 to C$5.3 billion. The ACCIP will include a grant of 12% for new eligible CCUS capital costs that will be paid to operators in three instalments over three years, following the first year of operation. This structure is similar to that used by the **Alberta Petrochemical Incentives Program**. Portions of the funding for the ACCIP will come from the Provincial Technology Innovation and Emission Reduction Fund. Provincial funding will be available after the federal government enacts the CCUS ITC and associated operational aids, such as contracts for difference. The ACCIP will be structured to supplement the federal CCUS ITC. The government of Alberta is in the process of finalizing the specifics of the ACCIP and further information is expected to be available in spring 2024.

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Our National Energy Group is at the forefront of the energy transition, structuring itself with legal and advisory support in all of the emerging energy sectors. These emerging sector groups are comprised of individuals from across the country, from multiple practice areas and with robust and varied expertise, providing our clients with competent, skilled and experienced teams of advisors.

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