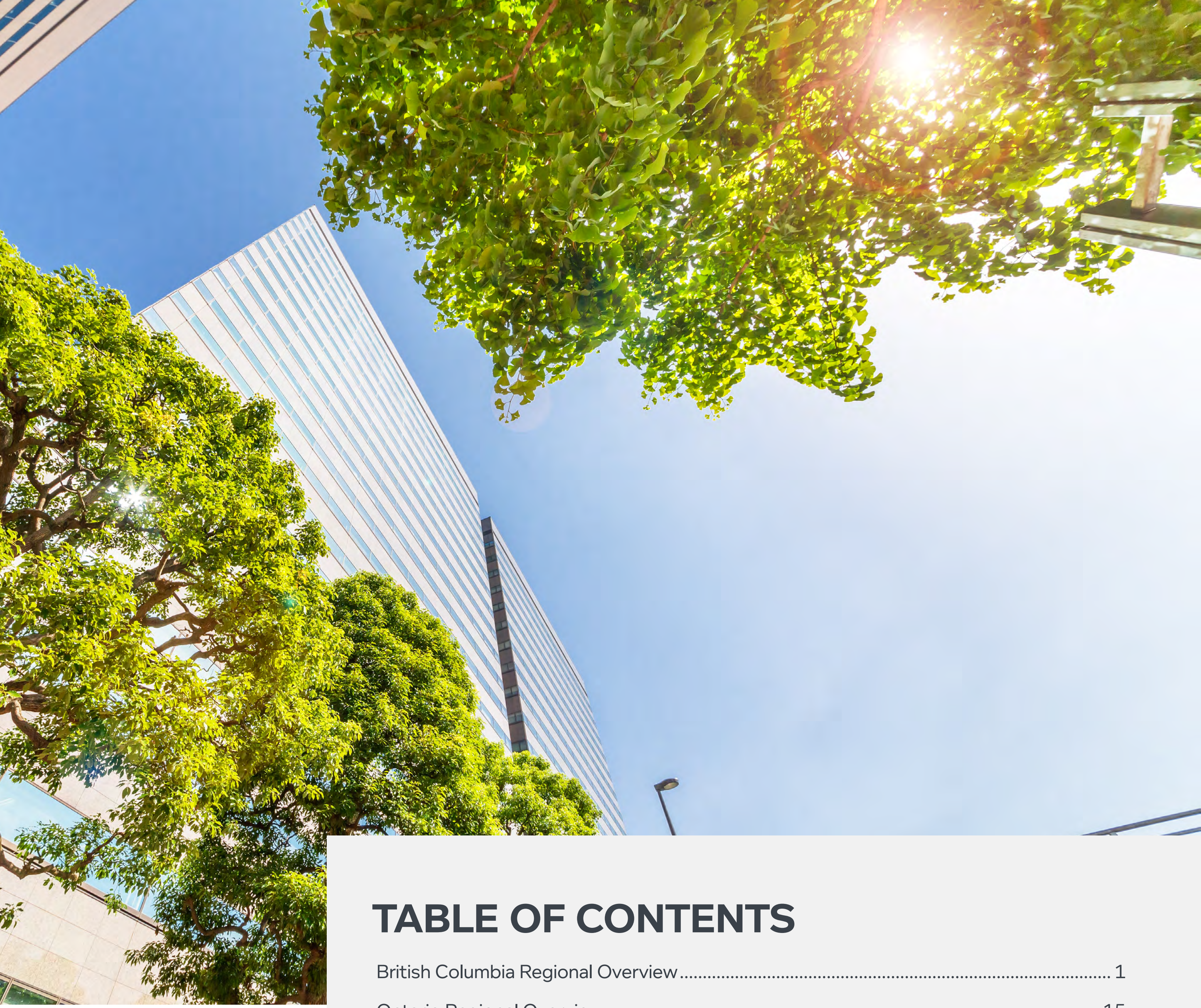
Power Perspectives

2025

The **National Energy Group of McCarthy Tétrault LLP** is pleased to present: *Power Perspectives 2025*.

Message from our Co-Editors-in-Chief, Kerri Howard and Jacob Stone: This publication is our tenth 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 2024. 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 2025. We hope that you will find this publication to be both interesting and informative.

Editors' note: The content of this publication is current as of December 31, 2024. On January 6, 2025, the Governor General prorogued the Canadian Parliament at the request of the Prime Minister. Prorogation suspends Parliament and no parliamentary business will occur while Parliament is prorogued. Unenacted government bills lapse and fall away, and any studies and hearings by parliamentary committees will cease. As a result, certain legislative outlooks and timelines for 2025 covered in this publication may be altered by prorogation. Please reference our **Prorogation of Parliament: What you Need to Know** article for more information.



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British Columbia Regional Overview

In 2024, a significant response to BC Hydro and Power Authority's ("BC Hydro's") **call for power** ("Power Call"), along with the advancement of a number of decarbonization initiatives in the province of British Columbia, signalled a bright future for clean energy production in British Columbia. Through the Power Call process, BC Hydro positioned itself to integrate more wind and solar energy into the grid by as early as 2028. In 2024, we also saw the utility continue its EPA Renewal Program while several liquid natural gas projects in British Columbia achieved significant milestones and the long-awaited Site C hydroelectric project further progressed towards its operational date.

BC HYDRO'S CALL FOR POWER

On April 3, 2024, BC Hydro issued the Power Call, its first competitive call for power in 15 years. The Power Call aimed to acquire approximately 3,000 gigawatt hours per year ("GWh/y") of renewable, emission-free electricity that could be on-line as early as the fall of 2028. The Power Call targeted an addition of 5% to the current energy supply – enough to power 270,000 homes or one million electric vehicles per year.

In 2022, BC Hydro identified the need to prepare for a significant power procurement in response to developments identified in the 2021 Integrated Resource Plan ("2021 IRP") Signpost Update (see **Power Perspectives 2024** for more information). The Signpost Update, among other things, confirmed the need for new sources of power in the province sooner than what was expected in the 2021 IRP. While BC Hydro's energy forecasts in 2021 anticipated an energy surplus of 500 GWh, the 2023 updates anticipated an energy deficit of 3,500 GWh by 2030 with electricity demand projected to rise 15% over the same period.

Engagement Sessions

After announcing the Power Call in June 2023, BC Hydro began an extensive **engagement and consultation process**, hosting information sessions, workshops, technical sessions and consultations with independent power producers ("IPPs") and **First Nations**. Between June 2023 and the end of the engagement phase in January 2024, BC Hydro engaged 99 First Nations, hosted 31 information sessions, focus groups and engagement sessions, and received over 2,500 individual pieces of feedback. The findings from the engagement sessions were used to update the draft **Request for Proposals** ("Draft RFP"), circulated in 2023.

Response to RFP

The Power Call received a strong response. By the submission deadline of September 16, 2024, BC Hydro received 21 proposals from across British Columbia. In total, the proposals amounted to more than 9,000 GWh/y – more than three times BC Hydro's target and enough to power approximately 800,000 homes.

The proposals primarily consisted of wind energy projects (70%), followed by solar (20%), and a combination of biomass and hydro (10%). The proposals represented a broad geographic distribution, spanning various regions of the province, including the Southern Interior, Central Interior, North Coast, Peace Region and Vancouver Island. Such varied locations could boost regional economic growth and diversify energy sources in British Columbia. The variety of participants is illustrative of a province-wide interest in developing clean, renewable energy projects with a focus on wind and solar power.

Proposal Assessment

BC Hydro assessed the proposals based on the criteria outlined in its revised **Request for Proposals**. First, projects were evaluated for eligibility. Then, the assessment was a qualitative and quantitative exercise.

Eligibility

To participate in the Power Call, projects are required to be located in British Columbia (excluding Fort Nelson and other areas not integrated with BC Hydro), connect or deliver to BC Hydro's integrated system without passing through another jurisdiction, and be a new facility, although expansions to existing facilities that consist of new generating units are also eligible. Each eligible project also needed to qualify as a clean or renewable resource as defined in the ***Clean Energy Act* (British Columbia)** ("CEA"), which includes wind, solar, hydro, biomass and geothermal heat. Projects must also use proven generation techniques and have an executed Competitive Electricity Acquisition Process IR filed with BC Hydro.

BC Hydro emphasized cost-efficiency by seeking larger projects that benefit from economies of scale and that can be constructed and brought online quickly. Projects must demonstrate a proven resource capable of producing between 40 and 200 megawatts ("MWs") and achieve commercial operation between October 1, 2028, and October 1, 2031.

Projects are also required to comply with the requirements for First Nations equity ownership, with 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 (see below for more detail).

Qualitative and Quantitative Assessment

After satisfying the eligibility requirements, BC Hydro also conducted a quantitative assessment of the proposals using evaluation adjusters which were then applied to the bid price. An evaluation price was determined by converting the bid price in the proposal to a levelized-real bid price of equal value. Then, the levelized-real bid price is adjusted to account for project attributes. The evaluation price was solely used for the proposal assessment phase, and is not the amount that will be paid for energy under the energy purchase agreement ("EPA").

BC Hydro also reviewed the **First Nations Consultation and Economic Participation** materials to determine if the proponents had adequately consulted with First Nations. This requirement was added in 2024 having been absent from the Draft RFP published in 2023. Proponents were required to have consulted comprehensively with First Nations potentially affected by their proposed project, detailing their engagement efforts, methodologies for identifying the relevant groups and the chronology of consultations. BC Hydro evaluated these efforts based on several criteria, including the impact on Aboriginal rights and the effectiveness of communication. Proponents provided documentation, such as communication records, shared information and agreements, to substantiate their consultation activities.

BC Hydro also had the discretion to consider broader factors, including:

- the proposal's impact on the interconnection, transmission, and generation infrastructure
- how the proposal fits with BC Hydro's current load/resource balance;
- the environmental implications of the project;
- the proposal's alignment with BC Hydro's strategic goals;
- the long-term and annual costs associated with the proposal;
- the balance between commercial and non-commercial trade-offs, including the security of electricity supply and market competitiveness; and
- other public interest factors, especially those affecting ratepayers.

BC Hydro had the discretion to conduct reference checks, background investigations, and could request additional information, interviews or presentations to clarify and validate submissions. Proposals could be rejected for various reasons including lack of clarity, inadequate commercial terms, insufficient qualifications or non-compliance with evaluation criteria. BC Hydro was also willing to dismiss proposals due to financial instability, safety concerns or cybersecurity issues.

First Nations Participation

As part of BC Hydro's commitment to economic reconciliation, it **collaborated with First Nation groups** in designing the Power Call and the **specimen electricity purchase agreement**. Under the **Power Call**, the First Nations economic participation model consists of three components:

1. As noted above, a minimum 25% First Nations equity ownership in each project, assessed on a pass/fail basis. Such minimum First Nations equity ownership must be maintained until the third anniversary of the project's commercial operation date. If the proponent cannot certify at the commercial operation date ("COD") of the project and on each of the first three anniversaries of COD, that the requisite level of First Nations equity ownership has been maintained, the energy price will be reduced by 5% for deliveries in the subsequent year or the EPA could be terminated.
2. Evaluation credits to acknowledge First Nations equity ownership in excess of the minimum 25% First Nations equity ownership, up to 51%. In particular, more credit will be given for 49, 50 or 51% First Nations equity ownership than for a 26–48% equity interest.
3. Non-equity economic benefits accruing to non-equity owner First Nations under a proposal. Non-equity benefits may include royalties, jobs, training, procurement and other investments in non-equity First Nation communities. This credit is designed to spread benefits across First Nation communities.

In addition to funding opportunities made available by the Canada Infrastructure Bank, proponents have access to the First Nations Equity Financing Framework, which was launched by the British Columbia government ("Government") in February 2024. The framework includes a special account with an inaugural balance of C$10 million to support immediate capacity funding needs for First Nations considering equity participation in priority projects. The account will have a cumulative loan guarantee of C$1 billion and will be reviewed annually. See the **Financing** section of this chapter for further discussion of government and BC Hydro funding programs.

Looking Forward

In December 2024, BC Hydro **selected nine energy projects** from the Power Call, and the successful proponents and First Nations partners are set out below:

Project/Region	Proponent	IPP Partner	First Nations Partner
Boulder and Elkhart Wind Project (South Interior West)	Elkhart Wind Limited Partnership	Elemental Energy	Upper Nicola Band
Brewster Wind Project (Vancouver Island)	Brewster Wind Inc.	Capstone Infrastructure	Wei Wai Kum First Nation
Highland Valley Wind Project (South Interior West)	Highland Valley Wind Inc.	Capstone Infrastructure	Ashcroft Indian Band
K2 Wind Project (South Interior West)	K2 Wind Power Inc.	Innergex Renewable Energy Inc.	Westbank First Nation
Mount Mabel Wind Project (South Interior West)	Mount Mabel Wind Inc.	Capstone Infrastructure	Lower Nicola Indian Band
Nilhts'I Ecoener Project (Central Interior)	Nilhts'I Ecoener Energy Corp	Ecoener	Lheidli T´enneh
Nithi Mountain Wind Project (North Coast)	General Partnership	Innergex Renewable Energy Inc.	Stellat'en First Nation
Stewart Creek Wind Project (Peace Region)	Stewart Creek Power Inc.	Innergex Renewable Energy Inc.	West Moberly First Nation
Taylor Wind Project (Peace Region)	Taylor Wind Project Inc.	EDF Renewables	Saulteau First Nations

Successful proponents were required to execute the EPA (and related side letter) no later than 10 business days after receiving the EPA from BC Hydro. Condensed timelines and other unique features of the Power Call, including the significant commercial involvement of First Nations as true risk sharing partners, intensified the challenges for potential proponents (see also Considerations for Wind Power Projects below).

The development and construction of these new clean-energy projects are anticipated to inject between C$2.3 billion to C$3.6 billion in private capital spending throughout British Columbia, creating an average of 800 to 1,500 jobs annually. BC Hydro's strategic calls for power, coupled with the initiatives proposed in the province's Capital Plan (as hereinafter defined), are projected to stimulate around C$40 billion in public and private capital investments, creating an estimated 11,300 to 14,000 construction jobs in total each year.

As a function of its "**Powering Our Future: BC's Clean Energy Strategy**," the province has committed to routine, competitive calls for power ensuring the province meets its clean electricity requirements while the economy and population grow. BC Hydro expects a rise in power demand in the coming years, with the next call for power in 2026 and potential calls every two years thereafter.

10-YEAR CAPITAL PLAN

In January 2024, BC Hydro released its 10-Year Capital Plan, called the **Power Pathway: Building B.C.'s Energy Future** ("Capital Plan") The Capital Plan includes C$36 billion in investments for regional and community infrastructure across British Columbia – a 50% increase from the previous plan. This Capital Plan not only aims to enhance electricity generation but also focuses on expanding and strengthening the transmission and distribution system. It is designed to efficiently deliver

clean power to new residential, commercial and industrial developments as required.

Nearly C$10 billion will be directed towards new electrification and gas reduction efforts, while C$21 billion will be allocated to improving system assets. The remaining C$5 billion will be used to connect new customers, particularly in high-growth areas across the province.

With a surge in population, and with it residential, commercial and industrial electrification, energy demands are soaring. To address this, approximately C$2 billion is being invested in various projects in the Lower Mainland and Vancouver Island, including the construction of new substations and the expansion of existing ones, alongside enhancements to the transmission lines and distribution network. These construction projects are projected to create an annual average of 10,500 to 12,500 jobs and will maintain BC Hydro's capital investments at a substantial level, particularly as major projects like Site C reach completion in 2025.

CONSIDERATIONS FOR WIND POWER PROJECTS

In the Power Call, all of the projects awarded EPAs (over 1,500 MW in total) were wind farms. Historically dominated by hydroelectricity, with a legacy of large storage-hydroelectric assets forming its backbone, the province's electric grid contains strong fundamentals to support the growth of wind energy. However, the grid-scale uptake of wind electricity in a province with low current utilization of such technologies engages certain legal and policy considerations around system-level management.

As wind electricity generation is intermittent, it cannot be relied upon to provide firm base load at any given time. Large sources of firm energy, such as storage hydro projects with large reservoirs that can be drawn upon as needed, are critical to supporting a diversified mix of renewable energy sources. As the province electrifies and the population and economy continue to grow, however, increased demands are being placed upon the historical network of hydroelectric facilities at the same time that **climate change is impacting the reliability of British Columbia's water system**. Thus, with significant growth of wind energy generation in the province, there will be new pressures on the grid to match supply with demand in real time and to optimize energy flows to reduce waste. A strong and stable grid with redundant capacity and intelligent design is needed, and utility-scale battery storage will be a key element of grid flexibility. In their **latest integrated resource plan**, BC Hydro has stated a need to add up to 600 MW of battery storage capacity to the provincial grid by 2030, roughly equivalent to 5% of BC Hydro's entire generation capacity, signaling an evolution of their conception of the grid and a likelihood of future storage solutions to be pursued into the decades ahead. Further investments in smart grid technology, including in the areas of dispatch management and controls, are expected as BC Hydro engages in iterative resource planning. This will nurture a currently nascent market in the province for providers of such services and technologies, leading to new procurement processes, capital demands and regulations. With the wide array of **provincial energy objectives** set out in the CEA, these markets are likely to develop in the unique British Columbian context and navigating them will require robust understanding of local market and policy forces.

Increased battery storage also engages the issue of systematic energy loss, as energy generated at a wind farm and stored in a battery will be diminished both during the transmission to and from the battery facility, and when the energy is converted from electrical to chemical form and back to electrical again as it passes in to and out of the battery units. Similar limitations beset pumped storage hydro (for which British Columbia has **over 80% of all of Canada's potential capacity**), where surplus electrical energy is converted into mechanical energy to pump water up a gradient so it can be infused with potential energy to subsequently be converted back into electrical energy by running it downhill through a turbine.
Given BC Hydro's statutory mandate to ensure its electricity rates remain "**among the most competitive in North America**," additional costs from energy loss due to storage will need to be borne by either generators or BC Hydro itself without being passed on to consumers. The broad and tight regulation of BC Hydro's capital, revenues and expenditures by the British Columbia Utilities Commission ("BCUC") will likely ultimately require BC

Hydro to pass these additional costs to generators either in the form of lower electricity prices or in less favourable legal and commercial terms. There were some early doubts about the attractiveness of the terms offered under the Power Call. In particular, the large potential exposures for developers in the form of liquidated damages and other mark to market risks under the EPA that indicate BC Hydro's willingness to allocate risks to generators in service of policy objectives are speculated to have had a cooling effect for some potential participants in the Power Call. Revisions to the specimen EPA in subsequent calls for power will closely watched.

In addition to more storage and better management of electricity flows, expanded transmission capacity is needed to service the increased demands of a rapidly electrifying economy and to add the redundancies required to integrate intermittent sources of power across the province's large and diverse landscape. Commitments by BC Hydro to advance transmission and capacitor projects in the north and to continue considering options for expanded transmission to the north coast and Vancouver Island add needed focus to grid capacity in regions with strong wind energy potential. BC Hydro has also announced new investments in south coast transmission infrastructure to increase capacity in that region by 1,300 MW by 2040, in part through the addition of new substations, the expansion of regional transmission capacity, and the redevelopment of existing assets. C$21 billion out of the total C$36 billion in the Capital Plan will be dedicated to ensuring existing assets throughout the electricity system are able to accommodate increased demands on the system. As discussed in our last publication, political and economic momentum for Indigenous ownership of transmission assets in British Columbia continues to grow. This will have significant implications for the provincial grid, including for its governance, financing, and commercial operation, especially as large and capital intensive transmission projects such as the northwest transmission expansion continue to be advanced with strong **Indigenous leadership**. Government equity grant and loan guarantee programs for Indigenous infrastructure ownership (some of which are discussed in the **Financing** section of this chapter) are expected to form a key layer of the capital stack underpinning the current grid transformation.

ELECTRICITY PURCHASE AGREEMENT RENEWALS

The EPA Renewal Program commenced on June 15, 2023 from the Signpost Update to the 2021 IRP with the BCUC. The Signpost Update and the Power Call were followed by an **update to the 2021 IRP**. The Signpost Update, among other matters, confirmed the need for new sources of power in the province sooner than had been anticipated in the 2021 IRP. One such source of power was through a program to renew electricity purchase agreements ("EPA Renewals"), and selecting **19 EPAs** that were set to expire prior to April 1, 2026 to which BC Hydro offered standard EPA Renewal terms ("EPA Renewal Program").

On March 6, 2024, the **BCUC approved** the 2021 IRP, including a specific approval of the EPA Renewal Program ("2023 Approval"). Immediately upon the 2023 Approval as the first tranche of the EPA Renewal Program, the BCUC approved six EPA Renewals with IPPs pursuant to the process set out in **section 71** of the **Utilities Commission Act** (British Columbia) and the BCUC Rules. We summarized the EPA Renewal Program and those six initial EPA Renewals in **our publication last year**.

Since our last publication, two more projects (being the Coats Hydroelectric Project and the Upper Mamquam Hydroelectric Project, discussed below) have been approved pursuant to the EPA Renewal Program. In addition to those two EPA Renewals, the BCUC also approved a third EPA Renewal – the Moresby Lake Hydroelectric Project – after BC Hydro came to terms with the relevant IPP through a bilateral negotiation process.

Approvals Subject to the EPA Renewal Program

As a result of the two additional EPA Renewals subsequent to the 2023 Approval, eight of the original 19 EPAs subject to the EPA Renewal Program have now been approved.

<u>Coats Hydroelectric Project EPA Renewal</u>

The Coats Hydroelectric Project EPA originally expired on December 31, 2023. **The Coats Hydroelectric Project EPA Renewal** was filed by BC Hydro to the BCUC on February 28, 2024, and **approved by the BCUC** on April 11, 2024. The Coats Hydroelectric Project EPA Renewal will last 20 years, from January 1, 2024, until January 1, 2044. The Coats Project operates on Gabriola Island, British Columbia and is operated by Crofter's Gleann Enterprises.

The Coats Hydroelectric Project is a 160 kW capacity small-storage hydro facility capable of generating 0.4 GWh of annual generation output, accounting for only 0.5% of the 900 GWh potentially available under the EPA Renewal Program as a whole. The Coats Hydroelectric Project is the smallest Project of the 19 associated with the EPA Renewal Program. The energy price for the outputs of the

Coats Hydroelectric Project are C$58/MWh, increasing at 50% of the Consumer Price Index ("CPI") beginning January 1, 2024. The electricity that BC Hydro purchases from the Coats Hydroelectric Project will remain fixed at this inflation-adjusted rate for the Project's additional 20-year term.

Upper Mamquam Hydroelectric Project EPA Renewal

The **Upper Mamquam Project EPA Renewal** was filed by BC Hydro to the BCUC on September 12, 2024, and **approved by the BCUC** on October 10, 2024. The Upper Mamquam Hydroelectric Project EPA was set to expire on July 23, 2025. The current Upper Mamquam Hydroelectric Project EPA will continue on its terms until that date, after which the EPA Renewal will last for 20 years, from July 23, 2025, until July 23, 2045. The Upper Mamquam Project operates near Squamish, British Columbia and is owned by Canadian Hydro Developers, Inc.

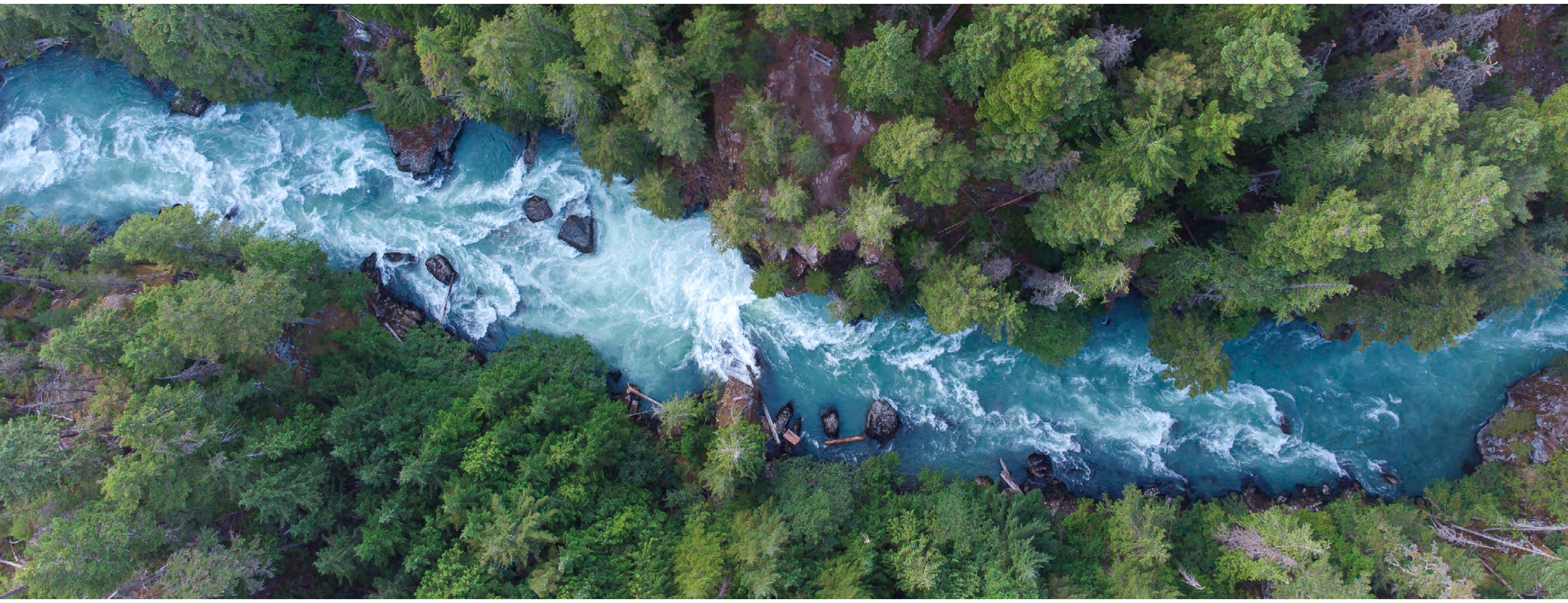
The Upper Mamquam Hydroelectric Project is a 25-MW capacity run-of-river hydro facility capable of generating 108 GWh of annual generation output, accounting for 12% of the 900 GWh potentially available under the EPA Renewal Program as a whole. Like the Coats Hydroelectric Project and all other fixed-rate project approvals stemming from the EPA Renewal Program, the energy price for the outputs of the Upper Mamquam Hydroelectric Project are C$58/MWh, increasing at 50% of CPI beginning January 1, 2024. The electricity that BC Hydro purchases from the Upper Mamquam Hydroelectric Project will remain fixed at this inflation-adjusted rate for the Project's additional 20-year term.

The Moresby Lake Hydroelectric Project Negotiated EPA Renewal

The **Moresby Lake Hydroelectric Project EPA Renewal** is unique, as it was a bilaterally negotiated contract for an EPA Renewal between BC Hydro and the relevant IPP for an EPA that was never subject to the EPA Renewal Program. As a result, the terms of the Moresby Lake Hydroelectric Project differ from the EPA Renewals subject to the EPA Renewal Program.

From March 23, 1989 until August 31, 2022, the Moresby Lake Hydroelectric Project operated under its original EPA. The BCUC's Moresby Lake Hydroelectric Project EPA Renewal implements both: (i) an extension of the EPA from March 1, 2024 until March 14, 2024; and (ii) the EPA Renewal, which will apply from March 15, 2024 until March 15, 2034. The electricity purchase price of the Moresby Lake Hydroelectric Project EPA Renewal is not publicly available, but is less than C$350/MWh, according to **BC Hydro's EPA Renewal Application** for the Moresby Lake Hydroelectric Project.

The Moresby Lake Hydroelectric Project operates near Sandspit, British Columbia on Haida Gwaii. The Project is operated by Atlantic Power (Coastal Rivers) Corporation (Atlantic Power). The project's expected annual generation output of 21 GWh represents about 75% of the energy needs of Sandspit. The only other currently viable alternative to this project for electricity supply to Sandspit would be met by diesel generation, which would be significantly more costly, and would have increased environmental impacts as compared to the Moresby Lake Hydroelectric Project.



Due to the Moresby Lake Hydroelectric Project's location in Haida Nation territory on Haida Gwaii, BC Hydro was required to consult with the Council of the Haida Nation about the EPA Renewal. As a result of this consultation, Atlantic Power entered into a Memorandum of Understanding with Tll Yahda Energy (**the clean energy Partnership of the Haida Nation**) in relation to the EPA Renewal. The details of the Memorandum of Understanding are not public. Subsequent to signing the Memorandum of Understanding, the Council agreed to accept the EPA Renewal.

The Moresby Lake Hydroelectric Project EPA Renewal application was filed by BC Hydro to the BCUC on May 14, 2024, and **approved by the BCUC** on August 23, 2024.

SITE C UPDATE

Almost a decade after work began on BC Hydro's Site C Clean Energy Project ("Site C"), a hydroelectric dam and generating station on the Peace River in northeastern British Columbia, the project is at last nearing completion, expected to achieve its final unit in-service date in fall 2025.

Downstream of the existing W.A.C. Bennett and Peace Canyon dams, **Site C** is expected to generate about 35% of the energy produced at the W.A.C. Bennett Dam with only 5% of its reservoir area by utilizing the waters of the Williston Reservoir (the province's largest reservoir), which will collect water to be used again in a newly created 83-km-long reservoir for water storage. Site C is projected to provide 1,100 MW of capacity and generate 5,100 GWh of energy annually, which BC Hydro states is sufficient to power 450,000 homes or 1.7 million electric vehicles each year. Overall, Site C is expected to increase **British Columbia's electricity supply by 8%**.

The 11-week project to fill Site C's newly created reservoir in the Peace River Valley began in late summer of 2024 and was completed in early November 2024, with the first of six 183-MW generating units coming into operation in October. The remaining units will be activated sequentially, with all six projected by BC Hydro to be operational by November 2025, realizing the **full extent of Site C's energy generation capacity**.

Site C has faced continual controversy, and BC Hydro's own **project reporting** acknowledges that despite nearing completion, the overall project health is moderate due to the overall schedule delays, remaining risks and spending. As of June 2024, costs were C$13.5 billion, with an estimated remaining expenditure of C$2.5 billion based on the forecasted total cost of C$16 billion – more than double the original estimated cost of C$6.6 billion. The project also faced multiple legal challenges in the course of its planning and implementation, including from Treaty 8 First Nations whose traditional territories were impacted by the project and its reservoir. BC Hydro has a mandate from the Government to enter into Project or Impact Benefit Agreements with the 10 Indigenous groups most impacted by Site C, and it **reports** that it has executed and implemented Project or Impact Benefit Agreements with eight out of 10 Nations and continues to extend an offer to negotiate with the remaining two Nations.

While at times the need for the electricity generated by Site C was debated, as we have reported in previous years, the energy needs for British Columbia now projected by BC Hydro suggest demand that will quickly outstrip the supply from Site C, opening opportunities for independent power producers to supply the shortfall.

CLEAN ENERGY INITIATIVES IN B.C.

British Columbia's Clean Energy Strategy

In June 2024, the Government released the province's new clean energy strategy, **Powering Our Future: BC's Clean Energy Strategy** ("Clean Energy Strategy"). The Clean Energy Strategy, which builds on other clean energy initiatives such as the BC Hydrogen Strategy and the Power Call, focuses on 10 areas including energy efficiency, increasing and diversifying clean energy sources, innovation and trading power with neighbouring jurisdictions. Actions under the Clean Energy Strategy include, among others: (i) investing C$700 million in BC Hydro energy-efficiency programs over the next three years; (ii) streamlining upgrades and new customer connections to BC Hydro's electricity grid to support the construction of new housing developments in growing communities; (iii) conducting regular, competitive calls for power every two years to meet growing demand; and (iv) increasing the target for renewable fuels produced in the province to 1.5 billion litres per year by 2030.

Update on CleanBC Roadmap to 2030

The **CleanBC Roadmap to 2030** ("CleanBC") provides the framework to reduce the province's emissions by 40% by 2030 and includes initiatives aimed at reducing emissions from a range of industrial sectors. As part of efforts to achieve the 2030 target, the Government transitioned from carbon taxes to an output-based pricing system ("OBPS") for industry on April 1, 2024. The OBPS is an industrial carbon pricing system and is mandatory for operations that emit over 10,000 tonnes of carbon dioxide equivalent ("tCO_2e") per year and incentivizes industrial emitters to reduce their emissions by using a performance-based system. Industrial operations within a regulated sector that emit less than 10,000 tCO_2e per year may opt-in to the OBPS. Under the OBPS, operations are assessed on an annual basis. Compliance emissions for April 1, 2024 to December 31, 2024, will be based on the emissions intensity of their production for the 2024 calendar year. Operations that emit under their annual emissions limit will earn credits, while operations that emit over their emissions limit will have compliance obligations. Compliance options include applying earned credits, provincial offset units or direct payments. As the transition to the OBPS is completed, the **CleanBC Industrial Incentive Program** ("CIIP") will be phased out.

To support the province's 2030 emissions targets under CleanBC, a new industrial electrification program under the CleanBC Industry Fund was introduced in partnership with BC Hydro in 2024 to support industrial electrification projects. See the **Financing** section of the British Columbia Regional Overview for further discussion of this program.

Financing

In 2024, the rollout of funding programs offered by the Government and BC Hydro in support of the Province's clean energy objectives continued. Two key focuses of these programs, particularly in relation to the Power Call, are (i) industrial electrification and (ii) ensuring meaningful Indigenous equity ownership. Some of these programs are discussed in more detail below.

Industrial Electrification

In furtherance of the province's ambitious 2030 emissions targets under the CleanBC framework, a new **industrial electrification program** under the **CleanBC Industry Fund ("CIF")** was introduced in partnership with BC Hydro in 2024 to support industrial decarbonization and emissions reductions projects in the province. The program will facilitate large industrial low-carbon electrification projects, namely through interconnection of industrial facilities into the BC Hydro clean energy power grid. To be eligible, an industrial operator must be a "reporting operation" under the ***Greenhouse Gas Industrial Reporting and Control Act* (British Columbia)** and must be an existing BC Hydro customer (or become a BC Hydro customer upon completion of the project).

Under this program, successful applicants can receive up to (A) 75% of eligible costs for capital funding (consisting of (i) funding under the CIF of up to C$25 million and (ii) project funding from BC Hydro determined by the demonstrated financial need for funding and the levelized incentive on a $/$tCO_2e$ basis for the project) and (B) 75% of eligible interconnection study costs under the CIF (up to a maximum of C$250,000 per project) for large-scale electrification projects. Funding awards for both categories of costs were determined on a project-by-project basis. BC Hydro has committed over C$5 billion over the next decade in their **2025-2034 Capital Plan** (see above for more detail) to industrial and other electrification programs.

Indigenous Equity Ownership

A number of targeted funding programs to ensure meaningful Indigenous equity ownership in clean energy projects are being utilized in the province.

Since our last publication, a **new funding stream** under the BC Indigenous Clean Energy Initiative ("BCICEI") to support the development of small-scale First Nation-led clean energy projects has been advanced. As we discussed previously, the Government announced a C$140-million contribution to this new BCICEI funding stream to accompany the Power Call, which is expected to help advance Indigenous-led projects that may not otherwise be competitive due to their smaller size. To be eligible for funding under the BCICEI funding stream, the following criteria must be satisfied:

1. applicants must be British Columbia First Nations, Tribal Councils or legal entities majority-owned and controlled by First Nations communities;
2. the projects being funded must also be majority-owned by First Nations;
3. the projects being funded must generate electricity from clean or renewable resources (as defined under the CEA); and
4. the projects being funded must be capable of connecting to BC Hydro's integrated power grid (which must also be able to accommodate the additional proposed electricity).

Preference will be given to projects that are wholly owned by First Nations, have previously received BCICEI funding under other streams, and are greater than BC Hydro's net metering program threshold and less than 15 MW in nameplate capacity.

Further supporting Indigenous equity ownership in clean energy projects, in their **Budget and Fiscal Plan 2024/25-2026/27** (Budget 2024), the Government announced a new First Nations Equity Financing Framework

("Framework") to support equity loan guarantees and other potential forms of assistance to facilitate Indigenous participation in projects. Amendments to the ***Special Accounts Appropriation and Control Act*** (British Columbia) passed in conjunction with Budget 2024 established a First Nations Equity Financing special account ("FNEF Account") on the Government's balance sheet with an initial balance of C$10 million to provide immediate capacity funding to Indigenous groups considering equity participation in projects. Under the *Special Accounts Appropriation and Control Act* (British Columbia), the provincial Treasury Board is authorized to fund the FNEF Account with government revenue and the Minister of Finance may provide capacity grants and loan guarantees to support Indigenous equity participation in projects up to an aggregate loan guarantee limit of C$1 billion. Although this loan guarantee program will not be rolled out in time for use in the current Power Call, it is expected to be deployed for use at scale in subsequent BC Hydro calls for power.

In further support of the First Nation ownership requirements under the current and future BC Hydro calls for power, Canada Infrastructure Bank ("CIB") announced **two new financing products** for call participants. These are an Indigenous equity loan program to help First Nation project participants finance up to 90% of their equity holding in a project that receives an electricity purchase agreement and a CIB program to extend investment tax credit bridge financing for up to 30% of project costs (see Tax Incentives for Clean Energy chapter of this publication for further details). These two CIB products must be used together for a given project, and cannot be used independently. Documents related to this financing program are being sent directly to call participants by CIB.

These funding and loan guarantee programs dovetail with the First Nations ownership requirements under the Power Call, which are expected to be carried forward into future BC Hydro calls for power.

FortisBC

FortisBC, both the largest gas utility and the largest private electrical utility in the province, has been engaging in its own clean energy development and procurement initiatives to reduce its greenhouse gas emissions while expanding its service offerings to meet growing demand. For gas, a major focus of FortisBC has been decarbonizing its natural gas operations while meeting delivery requirements under its regulated rate framework. On the electricity side, FortisBC has launched a Request for Expressions of Interest for New Power ("RFEOI") to evaluate options for procuring clean electricity to supply future demand. Both are discussed in further detail below.

Decarbonization

FortisBC has invested almost C$5 million annually between 2020 and 2024 towards clean energy innovation projects in the province through their Clean Growth Innovation Fund. These investments have supported the research and development of hydrogen and renewable natural gas fuel technologies, as well as carbon capture utilization and storage and energy efficiency programs. On April 8, 2024, FortisBC sought approval from the BCUC to continue the fund beyond 2024 as part of its Application for Approval of a Rate Setting Framework for 2025 through 2027. The decarbonization of natural gas through blending with lower carbon fuels, carbon capture and reduction of leakage are expected to play a significant role in reducing emissions while leveraging existing utility infrastructure to save on capital costs in light of the large expenditures required for the energy transition.

Procurement of New Clean Electricity

To serve growing electricity demand in its service area, FortisBC expects to require up to an additional 100 MW of additional electricity by 2030 and up to 340 MW in additional capacity by 2040 (requiring as much as 1,100 GWh of annual energy by 2030 and up to 2,300 GWh of annual energy by 2040). To plan for this growth, in September 2024 FortisBC launched its RFEOI to survey the market for clean power sources and consider its supply options. The stated purpose of the RFEOI, which is a solicitation of interest and not a procurement process, is to "identify and gather information on potentially feasible generation projects in British Columbia and inform next steps." FortisBC will be exploring projects which utilize wind, solar, hydroelectricity, or other clean or renewable resources (as defined under the CEA), among other technologies. Projects of greatest interest will be those which have a nameplate capacity of 5 MW of more, are in the province (but not necessarily in FortisBC's service area), are Indigenous-led or have significant Indigenous ownership and are innovative and capable of adding value beyond the power they will supply. A range of supply capabilities, including firm and non-firm energy sources, will be accepted for consideration. The initial procurement process related to the RFEOI is expected to launch in Q2 of 2025. The procurement process that is launched from the RFEOI may be attractive to project proponents who are unsuccessful in the Power Call or who desire greater commercial flexibility to negotiate bespoke provisions in supply agreements tailored to their unique projects.

LIQUID NATURAL GAS ("LNG") UPDATE

In the past year, several LNG projects in British Columbia have achieved significant regulatory, construction and financial milestones.

Currently, there are seven Canadian LNG export projects at various stages of development – all of which are located in the province In May 2024, the federal government **reported** that these projects could represent capital investments of around C$109 billion. As of November 2024, the federal government has granted five LNG export licenses, ranging from 25 to 40 years, thus setting the stage for LNG exports to start as early as 2025.

Furthermore, the re-election of the incumbent Government in 2024 has mitigated some of the uncertainty injected into the LNG industry by the provincial election cycle. The now re-elected NDP Government has expressed, albeit qualified, support for LNG projects in the province. In 2023, they introduced an **energy action framework**, which proposed new requirements for future LNG facilities and the province's oil and gas industry participants to align with the province's emissions-reduction goals. Shortly thereafter, the Government issued its **Oil and Gas Emissions Cap Policy Paper**. 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 September 2024, **LNG Canada** – a joint venture between Shell, Petronas, PetroChina, Mitsubishi Corporation and Korea Gas Corporation – **reported** its Phase 1 construction was 95% complete with natural gas introduced to the facility for the first time.

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, British Columbia, 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, we are not aware of final plans having been made to build the required infrastructure in time to make the Phase 2 build-out electric.

Cedar LNG

Cedar LNG made a **final investment decision** ("FID") in June 2024 to solidify the Cedar LNG project's status as the largest Indigenous majority-owned infrastructure project in Canada. Cedar LNG is a Haisla Nation majority-owned partnership with Pembina Pipeline Corporation. This US$4-billion project is also proposed to be located in Kitimat, British Columbia, on Haisla Nation-owned land, and would be supplied with natural gas from the now-complete Coastal GasLink pipeline. When built, Cedar LNG would produce approximately three million tonnes of LNG per year.

Notably, British Columbia's energy action framework was announced after the **approval** of the Cedar LNG project in 2023, 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.

Other 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, British Columbia, is currently under construction with work foundations for the LNG processing equipment and modules **expected to arrive in 2025**. 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

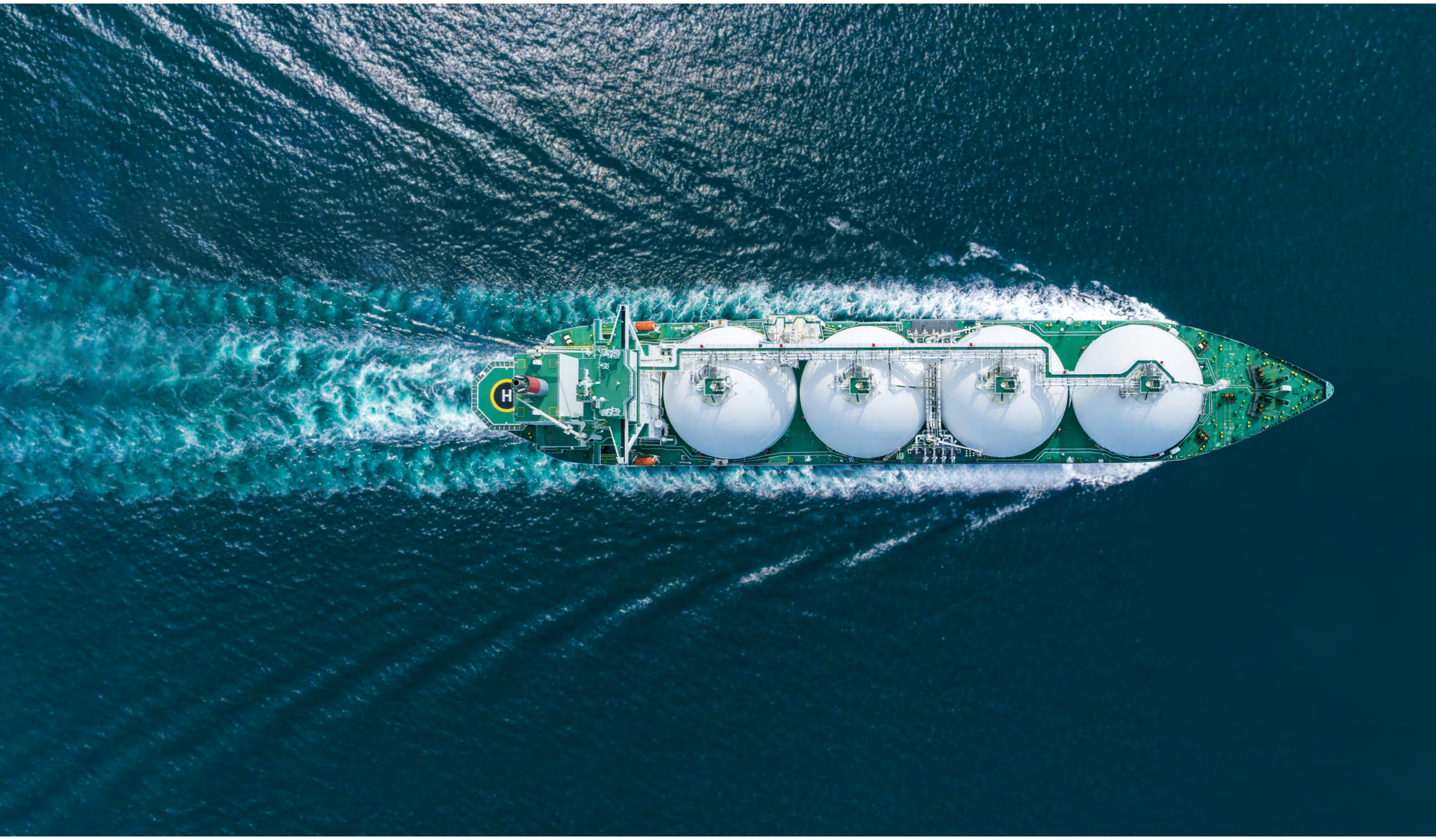
In 2024, **Ksi Lisims LNG**, a Nisga'a Nation-led C$10-billion project which also includes Western LNG and Rockies LNG, achieved two major milestones. First in January 2024, Ksi Lisims LNG finalized a **20-year LNG purchase and sale agreement** with Shell Eastern Trading Pte Ltd. This agreement comes less than a year after the Ksi Lisims LNG project received the **go-ahead** to enter the province's environmental review process. Second, on June 21, 2024, the Nisga'a Nation and Western LNG **purchased** the Prince Rupert Gas Transmission project ("PRGT") with plans to re-route the pipeline and connect it to Ksi Lisims LNG. The Ksi Lisims LNG project aims to export 12 million tonnes of LNG per year, making it Canada's second-largest LNG export facility.

The Ksi Lisims LNG project and PRGT are both under review by the Environmental Assessment Office (the "EAO"). 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 and obtain an environmental certificate. Accordingly, Ksi Lisims plans on using floating facilities, with hydroelectricity powering motors for compressors in the liquefaction process. In contrast, PRGT has an environmental certificate that was supposed to expire on November 25, 2024 and the EAO is reviewing a **request** by PRGT to make the certificate permanent.

Tilbury

Tilbury LNG is a proposed two-phased expansion of an existing FortisBC facility, located on Tilbury Island in Delta, British Columbia. FortisBC is in the early planning stages to complete Phase 1 of the expansion to its liquefaction capacity, which could complete construction as early as 2028.

In 2024, the proposed **Tilbury Marine Jetty** project, which would develop a jetty adjacent to the Tilbury LNG facility, received **federal** and **provincial** environmental assessment approval. The Tilbury Marine Jetty is administered by the Tilbury Jetty Limited Partnership, which is jointly owned by Fortis LNG Jetty Limited Partnership and Seaspan.



ONTARIO REGIONAL OVERVIEW

By Seán C. O'Neill, Gordon M. Nettleton, Suzanne V. Murphy, Kerri Lui, Mitchell Lui, Razan Mohamed, Maneet Kahlon, Emmanuel Onyemachi, Rachel Cristofoli, Mitchell Spragg and Nicholas Geringer

Ontario Regional Overview

ONTARIO'S GROWING ELECTRICITY DEMAND

The Ontario electricity industry experienced its own "October surprise" in 2024 with the announcement by the Ontario Independent Electricity System Operator ("IESO") that it had revised its forecast of its already expected significant **surge in electricity demand** in the province. The IESO revealed that this expected material increase in previously forecasted demand was primarily driven by the predicted rapid expansion of data centres and the growing adoption of electric vehicles ("EVs").[1] According to the IESO, electricity demand in Ontario is projected to increase by 75% by 2050, with annual consumption rising from 151 terawatt-hours ("TWh") in 2025 to 263 TWh in 2050. The Ministry of Energy and Electrification's ***Ontario's Affordable Energy Future*** report released in October 2024 outlines both the challenges the province will face due to this surge and the strategies to manage the increasing demand.[2]

The proliferation of data centres within the technology sector is a major driver of rising electricity demand. These data centre projects are emerging to support advanced technologies, such as artificial intelligence (AI), and are expected to grow substantially over the next 15 years. The rising adoption of AI is also anticipated to contribute to higher energy consumption.

The industrial and transportation sectors are undergoing a transformative shift towards electrification. EV adoption is anticipated to be the largest driver of increased electricity demand, contributing 20 TWh or 31% of new demand by 2035. The IESO projects that electricity demand from EVs will grow from 1.6 TWh in 2025 to 41.6 TWh in 2050, resulting in an average annual growth rate of approximately 13.9%. This shift will not only significantly reduce emissions but also increase industrial demand by necessitating new supply chain and manufacturing facilities.

Another key factor contributing to rising electricity demand is Ontario's increasing population. The province's population is expected to grow by 15% by 2035, adding approximately one million more homes. This population growth is anticipated to further escalate electricity demand. As new housing developments emerge, the demand for residential electricity will rise significantly, particularly as households increase their consumption by electrifying heating and cooling systems.

Demand Strategy for Ontario

To address the rising demand, Ontario is focusing on expanding its electricity generation capacity by accelerating infrastructure development. This includes new investments and the expansion of nuclear energy. The emphasis is on reliable and clean energy to create a **competitive advantage** for attracting **both international and domestic investments**.[3] With growing electricity demand, there is also a need for new electricity generation and storage resources. **See Procurement**.

1 Independent Electricity System Operator, "**Electricity Demand in Ontario to Grow by 75 per cent by 2050**" (16 October 2024).

2 Ministry of Energy and Electrification, "**Ontario's Affordable Energy Future: The Pressing Case for More Power**" (October 2024).

3 Ministry of Energy and Electrification, "**Ontario Ready to Meet the Challenge of Soaring Energy Demand**" (22 October 2024); Ministry of Energy and Electrification, "**Ontario's Affordable Energy Future: The Pressing Case for More Power**" (October 2024).

The surge in electricity demand presents both challenges and opportunities. In ***Ontario's Affordable Energy Future*** report, the government announced an integrated energy plan to be launched in 2025 to manage energy demand while prioritizing energy affordability. This integrated plan will coordinate all energy resources, including nuclear, hydroelectricity, natural gas, hydrogen, renewables and other fuels. A key goal of this coordinated planning is to achieve greater alignment across the various energy sources.

The province also emphasizes energy efficiency programs, noting that without such initiatives, provincial energy demand would already be 15% higher. Consequently, Ontario's integrated plan includes efforts to reduce energy consumption alongside increasing power generation. The government plans to significantly expand energy efficiency programs starting January 1, 2025.

ONTARIO'S COMMITMENT TO AN ELECTRIFIED FUTURE: *AFFORDABLE ENERGY ACT, 2024*

In concert with the anticipated increases in electricity demand and capital expenditures to meet such demand, the Government of Ontario has advanced legislation designed to transform the province's energy landscape. The *Affordable Energy Act, 2024*[4], also known as Bill 214, aims to establish long-term energy planning, introduce noteworthy amendments to energy system codes, and develop a comprehensive framework for EV charging infrastructure. Bill 124 was introduced by the Honourable Stephen Lecce, Minister of Energy and Electrification, on October 23, 2024 and received royal assent on December 4, 2024.

During the first reading of Bill 124, Hon. Lecce described Bill 124 as one that:

> "would enable the implementation of the province's first integrated long-term energy plan with a focus on affordability. It would also prioritize zero-emission nuclear energy to meet growing energy demand, expand programs to help families and businesses save money and energy, support EV adoption and, as well, reduce last-mile connection costs."[5]

The preamble of the *Affordable Energy Act, 2024* also lays out the Ontario government's vision. It acknowledges the need to meet increasing electricity demands due to economic growth, electrification, and population growth. Bill 124 supports a prosperous economy that reduces emissions without relying on measures like carbon taxation. It emphasizes keeping energy affordable and acknowledges the importance of public engagement, Indigenous reconciliation, and the potential for energy export.

The Act amends the *Electricity Act, 1998*, the *Ontario Energy Board Act, 1998*, and the *Energy Consumer Protection Act, 2010*. However, Part VIII of the *Electricity Act, 1998*, which deals with electrical safety, still applies. It includes three schedules, each addressing different aspects of the energy sector.

Schedule One: Electrifying Energy Planning

The first schedule of Bill 214 focuses on energy planning in Ontario. The *Electricity Act, 1998* would be amended to include a new goal of promoting electrification and energy efficiency to reduce emissions across the province through increased use of electricity. This is part of a broader objective to support a clean energy economy and sustainable growth.

Section 25.29 of the amendments introduces a significant change by granting the Minister the authority to issue integrated energy resource plans unilaterally, following consultations with stakeholders and approval from the Lieutenant Governor. This new process replaces the previous long-term energy plans to better align with governmental goals and objectives over specified periods. Additionally, these energy resource plans must reflect the goals and objectives outlined in section 25.29(2). Furthermore, while the IESO and the Ontario Energy Board ("OEB") are required to comply with this new integrated planning approach, section 25.31 of the Energy Act – which mandated the submission of implementation plans by the IESO and the OEB to the Minister – has been repealed.

Schedule Two: Rethinking the System Codes

The second schedule introduces two new regulatory powers regarding the Distribution System Code and the Transmission System Code. The first, under Section 70.4, authorizes the Lieutenant Governor in Council to enact regulations specifying amendments to either code concerning cost allocation and recovery associated with the construction, expansion, or reinforcement of distribution and transmission systems. These amendments will be deemed to have been issued pursuant to Section 70.1 and must be integrated into the relevant code. The chief executive officer is prohibited

4 *Affordable Energy Act*, **2024**.
5 Bill 214, *Affordable Energy Act*, **1st reading, Ontario Legislative Assembly, 43-1**, (23 October 2024) (Hon. Stephen Lecce).

from amending or revoking these amendments while the regulation remains effective.

The second regulatory authority, under Section 70.5, permits the Lieutenant Governor in Council to establish regulations that exempt individuals or entities from certain provisions of the Distribution System Code and the Transmission System Code related to cost allocation or recovery, subject to specified conditions or restrictions. However, while this streamlines the process, it may limit the OEB's flexibility in modifying or exempting specific provisions. Additionally, the broad scope of these regulatory powers, particularly in cost-related matters, could reduce transparency and public input, potentially leading to less accountability in the decision-making process, especially for consumers affected by these changes.

Schedule Three: Charging into the Future with Electric Vehicles

The third schedule addresses the rise of EV charging, a crucial aspect of Ontario's electrification strategy. The *Electricity Act, 1998*, the *Energy Consumer Protection Act, 2010*, and the *Ontario Energy Board Act, 1998*, are amended to define terms related to EVs and charging stations. Moreover, the legislation stipulates that these acts will not apply to the distribution (i.e., delivery) or retail (i.e., sale) of electricity for EV charging unless specified by regulations. This stipulation establishes a regulatory sandbox, facilitating innovation and investment in EV infrastructure by minimizing the regulatory hurdles for potential investors in this sector.

Conclusion

The *Affordable Energy Act, 2024*, marks a considerable advancement in Ontario's energy policy. It exemplifies a firm commitment to emission reduction through electrification and enhanced energy efficiency. The legislation emphasizes the integration of long-term energy planning with the requirements of a growing economy and the transition to EVs, positioning Ontario as a leader in sustainable energy management. The government's endorsement of a diverse array of energy resources and the modernization of infrastructure ensures that the province is well-prepared to meet future demands and stimulate economic growth, both within the province and through energy exports.

Nevertheless, while the Act aims to support economic growth and affordability, its long-term economic implications for Ontario remain uncertain. The shift towards an even more extensively electrified energy system is expected to be accompanied by economic challenges given the enormity of the projected capital requirements to achieve Ontario's ambitions.

IESO MARKET RENEWAL PROGRAM

Twenty-Three Years After Market Opening, MRP Set to Go Live

Among other important functions, the IESO serves as the operator and mainstay for the reliability and security of Ontario's electricity grid and the administrator of Ontario's electricity markets. Its objects focus upon providing Ontarians with reliable power when needed. The IESO has operated the Ontario wholesale electricity market since it opened on May 1, 2002, however, the IESO has also viewed that market as requiring improvement since then. After years of planning and effective May 1, 2025, the IESO will finally implement its Market Renewal Program ("MRP"). The initiative aims to foster more efficient electricity markets and secure cost-effective, reliable power for Ontario residents.

Some of the main drivers for MRP are two fundamental flaws that the IESO has perceived to be inherent in the current electricity market and incompatible with contemporary needs:

i. **Ensuring Reliability:** The existing market operates under a two-schedule design. One schedule sets a uniform price across Ontario for electricity to be paid by the IESO ignoring physical limitations or costs of suppliers. The second schedule dispatches electricity based on locational constraints. Thus, the two-schedule design risks supply shortages when prices do not align with supplier offers or abilities. To counter this, the IESO makes payments to suppliers to ensure reliable price-offer alignment, which payments are settled "out-of-market" and not reflected in the published wholesale market commodity price (i.e., the hourly Ontario energy price, better known as "HOEP").

ii. **Transparency:** Transparency is limited in the existing market, offering only a partial view of operations for the day-ahead and current operating day. Consequently, the market relies on out-of-market payments to ensure resource availability, which can be expensive as they cover both the energy supplied and the operating costs of suppliers from one region fulfilling the demands of another.

The MRP has been designed to introduce **three key reforms**:

1. **Single Schedule Market ("SSM"):** As a replacement to the two-schedule system, the SSM features locational pricing to replace HOEP and to ostensibly correct price-supply misalignments and eliminate the out-of-market payments arising from grid restraints.

2. **Day-Ahead Market ("DAM"):** A DAM is a system where energy is bought and sold one day before it is consumed or generated. Implementing a DAM is intended to provide operational predictability for the IESO and financial assurance for market participants, thereby reducing electricity production costs and committing only essential resources.

3. **Enhanced Real-Time Unit Commitment ("ERUC"):** The ERUC initiative is intended to lower the costs of scheduling and dispatching resources to meet fluctuating demand from day-ahead to real-time. The ERUC will observe several hours at a time, replacing the current hour-by-hour approach and intended to thereby enhance the predictability of scheduling and service reliability.

The objective of MRP is to revamp the wholesale electricity market by integrating the above initiatives in order to create a diverse and decentralized variety of energy resources. Specifically, the IESO stated the following:

> "**Together, these changes** will deliver significant ratepayer savings, ensure continued reliable operations of the system, and support the transformation underway within the electricity sector."

The **IESO published a business case in 2019** that estimated over the first ten years following its rollout, the IESO anticipates the MRP to deliver net gains amounting to $800 million. Of these anticipated benefits, enhancements in market efficiency will yield $525 million while reduced out-of-market payments will amount to $275 million. The forecasted implementation and ongoing operational expenses stand at $176 million. Nonetheless, a 2022 reassessment scaled back these net benefit expectations to $700 million for the first 10 years following the MRP's introduction, without offering additional forecasts.

Market Rule Amendments Facilitating the Market Renewal Program

On October 24, 2024, the IESO Board of Directors **approved amendments to several market rules** required to operationalize the MRP. A summary of the amendments can be found at the **Market Renewal Program: Summary of Market Rule Amendment Batches** and include establishing a market power mitigation working group which will assist with determining reference levels and quantities for electricity resources. The Board's approval comes on the heels of a unanimous recommendation made by the IESO's Technical Panel. As of November 11, 2024, the IESO amendments took effect with the purpose of facilitating registration activities ahead of the MRP's launch.

Amending IESO Contracts to Align with the Market Renewal Program

In the lead up to the anticipated launch of MRP on May 1, 2025, the procurement and contracting side of the IESO has been conducting stakeholder information sessions. It has also been providing terms sheets and draft amending agreements for the myriad procurement contracts it has assumed or entered into since the creation of its predecessor, the Ontario Power Authority, in 2004. The market rule evolution provisions of the oldest of such contracts serve as a reminder that the DAM has been on the IESO to-do list for over two decades.

PROCUREMENT

Ontario's Second Long-Term Procurement

On **August 28, 2024**, the Government of Ontario announced the launch of the IESO's second "Long-Term Procurement" ("LT2"). This initiative supports the province's strategy to secure up to 5,000 megawatts ("MW") of generation capacity (14 TWh of annual energy generation from eligible energy producing resources and up to 1,600 MW of eligible generation capacity) through multiple procurements. This newest IESO procurement builds on the government's recent acquisition of nearly 3,000 MW of new battery storage projects with capacities ranging from 5 MW to over 400 MW.

The IESO released a draft of the **Long-Term 2 Request for Proposals** ("LT2 RFP") on September 6, 2024 and has revised it and the accompanying LT2 contract several times since then. Generally speaking, LT2 establishes a framework for suppliers who seek to deliver year-round energy generation services in Ontario using new electricity generating facilities that exceed 1 MW. LT2 contemplates an energy stream and a capacity stream with similar but different LT2 RFPs and LT2 contracts for each. The IESO has indicated that the energy stream will be prioritized over the capacity stream and it plans to finalize the LT2 RFPs and contracts in Q1 of 2025.

LT2 is open to "technology-agnostic" energy resources including natural gas, wind, and solar, and the LT2 RFP outlines several key requirements and incentives. Developers must obtain municipal support resolutions to ensure local consent, and prohibitions relate to "specialty crop areas" and "prime agricultural areas." The framework incentivizes projects in Northern Ontario and those avoiding prime agricultural areas, and plans to utilize Crown lands for renewable energy. It also promotes economic opportunities for projects involving Indigenous communities and mandates agricultural impact assessments for projects in prime agricultural areas.

The LT2 also incorporates rated criteria points to evaluate proposals and lower the Evaluated Proposal Price ("EPP") upon which submissions will be judged. Points are awarded for Indigenous participation, projects not located on Prime Agricultural Areas, and projects located in Northern Ontario, with proponents able to receive up to 12 points to reduce their EPP. This approach aims to encourage project development in targeted areas and regions that may benefit from increased economic activity, emphasizing the importance of strategic project placement in the LT2 framework.

To protect agricultural land, the LT2 prohibits specific projects on agricultural land, including lands in specialty crop areas and prime agricultural areas. An agricultural impact assessment is required for projects on prime agricultural areas, and proponents who are awarded LT2 contracts must notify the IESO and provide supporting documents, including delivering the report to the relevant municipality's planning department, by the date eighteen months after the contract date. Failure to complete the assessment within this timeframe constitutes an event of default under the LT2 contract.

To further bolster Ontario's energy strategy, the IESO also launched the second **Medium-Term ("MT2") procurement** on November 15, 2024. The MT2 aims to reacquire resources that were subject to IESO procurements contracts that have or will expire before April 20, 2029, and to encourage investments to prolong the operational life of such facilities. This procurement also includes both capacity and energy streams, with a primary focus on price for eligibility.

Electricity Transmission Procurement

The IESO announced its latest design decisions for the **Transmitter Selection Framework** ("TSF"), a competitive procurement for new electricity transmission in Ontario, following a **July 10, 2023 directive from the Ontario Ministry of Energy**.

Proponents who successfully qualify through a Request for Qualifications will be added to a registry of approved electricity transmitters eligible to bid on future transmission projects. To qualify, proposals must benefit all electricity ratepayers and have an estimated cost of at least $100 million, a nominal voltage of 200 kilovolts or greater, and a lead time of at least six years.

Successful proponents under the TSF will receive partial contracts following commercial operation, after which the OEB will apply existing utility rate regulation mechanisms.

Transmitters must submit their projected costs for review via a cost-of-service application to the OEB. The revenue requirement, including post-commercial operation date revenue, will be fixed through an IESO contract and incorporated into the Uniform Transmission Rates ("UTRs"). This partial contract aims to control design and construction costs by setting a cap based on a fixed lifetime operations and maintenance plan. After the IESO contract expires, the OEB will apply its standard rate regulation, reviewing all cost components before they are included in the UTRs. This blended revenue structure is intended to balance competitive economic growth with long-term stability by maintaining price pressure through competition and attracting large-scale capital investment through rate regulation.

ELECTRIC VEHICLES

Overview of Manufacturing and Investments

Ontario has continued to attract significant investment into EV manufacturing. Over the last four years, **$45 billion** has been invested into Ontario by global automakers, parts suppliers, manufacturers of EV batteries, and battery materials. Federal, provincial and municipal governments have all supported new EV manufacturing projects. Some noteworthy investments over the past year have been:

— An investment of approximately **$5 billion** by NextStar Energy, a joint venture between LG and Stellantis that will build a state-of-the-art battery manufacturing facility in Windsor, Ontario. The project will receive both federal and provincial contributions potentially totalling $18.6 billion over its lifespan. The federal government will cover two-thirds of the combined production subsidies for NextStar and Volkswagen (PowerCo), while Ontario will provide the remaining one-third.

— An investment of over **$575 million** by Goodyear to modernize its Napanee plant, with an emphasis on producing tires for EVs. Invest Ontario will contribute $20 million to this project, along with $44.3 million from the federal government's Strategic Innovation Fund and approximately $2 million in incentives from the Town of Greater Napanee, the Township of Stone Mills and the County of Lennox and Addington.

— An investment of approximately **$15 billion** by Honda Canada to create Canada's first comprehensive EV assembly plant. Ontario has committed up to $2.5 billion toward this project through direct and indirect incentives, along with an additional estimated $2.5 billion from proposed federal tax credits.

The increased investment into EVs builds upon Ontario's plan to build a world-leading EV and battery supply chain. In its **2024 Budget**, the Ontario Ministry of Finance noted how "Canada's raw material resources, strong integration with the United States' automotive sector, and clear policy commitments have given it an edge over competitors." As manufacturers continue to choose Ontario for their facilities, its goal to become a world-leading jurisdiction for EVs becomes closer.

Development of Charging Infrastructure

As part of the province's increased focus on EVs, the Ontario Ministry of Energy is **exploring options** to reduce electricity rates for public EV chargers. This is part of a larger plan to encourage further development of charging infrastructure. Under existing rules, there is little incentive to build public EV charging stations in areas with low EV demand. Due to electricity costs to the developer and low revenue to cover such costs, charging stations in low-utilization areas are "**either not built or operate at a loss**."

Accordingly, the OEB has been conducting public consultations on a new EV Charger Discount Rate for public EV charging stations in areas with low utilization. The aim is to incentivize infrastructure developers to build additional chargers in these areas. If approved, a lower rate will be offered to public EV charging providers in low-utilization areas (between 50 kilowatts ("kWh") and 4,999 kW) beginning on January 1, 2026. The outcomes of the public consultations, such as the discounted rate to be charged, remain to be seen.

In addition to the reduced-rate plan, Ontario is building over **1,300 new EV charging ports** in small and medium-sized communities. These new charging stations are part of a "$63 million investment to build publicly accessible charging stations in communities with less than 170,000 people, as well as in any Indigenous community in Ontario." The Ontario government has placed an emphasis on smaller and underserved communities to provide more certainty to drivers during their commute while using EVs.

Ultra-Low Overnight Price Plan

Finally, the Ontario government has recently implemented their **Ultra-Low Overnight Price Plan**. Beginning in May 2023, customers of Toronto Hydro, London Hydro, Centre Wellington Hydro, Hearst Power, Renfrew Hydro, Wasaga Distribution and Sioux Lookout Hydro have been able to opt-in to this plan. This plan is designed to be particularly advantageous for those who charge EVs overnight, and helps prepare the grid for increasing electricity usage by EVs.

NUCLEAR AND SMALL MODULAR REACTORS

In 2024, Ontario's nuclear industry continued building off its accomplishments from last year. Near the beginning of the year, the Ontario government announced support for Ontario Power Generation's ("OPG") plan to proceed towards the **refurbishment of Pickering Nuclear Generating Station's "B" units**. OPG has completed the Project Initiation Phase of refurbishment and is now proceeding with the Project Definition Phase, with the refurbishment of Pickering Nuclear Generation Station anticipated to be completed by the mid-2030s. As part of the Project Definition Phase, OPG is authorized to sign a $2.1-billion contract with CanAtom, a joint venture of Aecon and AtkinsRéalis, for early engineering and procurement. The refurbishment is contingent upon regulatory approval by the Canadian Nuclear Safety Commission ("CNSC"). If the refurbishment proceeds, the Pickering Nuclear Generating Station's "B" units are expected produce 2,000 MW of electricity once refurbished, enough to power two million homes.

The government also confirmed that **OPG has completed the early works** for its closely watched small modular reactor project on time and on budget. The government's announcement noted that main site preparation is now underway by Darlington New Nuclear Project's construction partner, Aecon.

Ontario was also the recipient of up to **$50 million in federal funding** through the Electricity Predevelopment Program for Bruce Power's assessment of new generation opportunities in Tiverton, Ontario, which would have the potential to generate power for up to 4.8 million homes and businesses across the province. This project alone would account for more than a quarter of the new nuclear capacity needed by Ontario to meet its clean electricity demands in 2050 as recommended by the IESO. Additionally, Bruce Power **has submitted its Initial Project Description** for the proposed Bruce C project to the Impact Assessment Agency of Canada. This submission is part of the federal impact assessment process, which will evaluate the addition of up to 4,800 MW of electricity production at the Bruce Power site.

In April, the government welcomed an $80-million investment by BWX Technologies, Inc. to **expand their Cambridge nuclear manufacturing plant**, which will create new skilled, unionized jobs, support the ongoing efforts of Ontario's existing Darlington, Bruce and Pickering nuclear stations, and reinforce Ontario's global leadership on new nuclear technologies. Construction of the expansion project is expected to begin in the third quarter of 2024 with completion targeted for early 2026.

After more than a decade of collaboration with potential host communities, the Nuclear Waste Management Organization ("NWMO") announced in November the selection of the **Wabigoon Lake Ojibway Nation-Ignace area for Canada's deep geological repository for high-level nuclear by-products**. This milestone advances the NWMO's Adaptive Phased Management approach, established in 2007 for the safe, long-term management of nuclear waste, and adheres to international best practices. The project will now enter a thorough regulatory review process, including licensing by the CNSC and an integrated impact assessment.

ALBERTA REGIONAL OVERVIEW

By Robyn Finley, Kerri Howard, Kimberly Howard, Riley Thackray, Ashley Urch, and Ashley Wilson[1]

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Alberta Regional Overview

It has been another busy year in Alberta with energy industry support and electricity market reform as key drivers in changes to our policy and regulatory landscape. Following the regulatory pause on renewables and the Government of Alberta's (the "Province") stated intention of continuing to challenge federal initiatives on emissions reductions, we see continued support for a strong oil and gas industry and conventional generation, mixed with energy diversification initiatives.

Alberta is facing a major electricity market overhaul through the Restructured Energy Market (the "REM") with a focus on providing stable, reliable and affordable energy generation. While the REM takes shape, there is a level of uncertainty in the market that stakeholders are attempting to navigate as they consider project development and acquisition opportunities.

And let us not forget our energy transition initiatives, with the execution of the first Carbon Sequestration Lease Agreements for carbon sequestration hubs in the Province, among numerous other project announcements and developments in our emerging energy sectors. 2025 is bound to be another exciting year in the energy sector in Alberta, as we balance competing goals and initiatives in driving towards a sustainable energy future.

MARKET UPDATE

Regulatory Pause on Renewables

In August of 2023, the Province issued an order-in-council[2] pursuant to which the Alberta Utilities Commission ("AUC") was ordered to inquire into and report to the Minister of Affordability and Utilities ("MUA") on the ongoing economic, orderly and efficient development and operation of electricity generation in Alberta. The Province further issued a second order-in-council[3] enacting the *Generation Approvals Pause Regulation*[4] which restrained 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 (the "Renewables Pause"). On February 28, 2024, the Province lifted the Renewables Pause and, further to the AUC's **Module A Inquiry** and resulting report, **announced** policy guidance ("Policy Guidance") regarding its intention to advance what it deemed necessary policy, legislative and regulatory changes to the renewables regime in Alberta. The Policy Guidance was further supplemented by the **announcement** of the new *Electric Energy Land Use and Visual Assessment Regulation*[5] ("Land Use and Assessment Regulation") as well as amendments to the *Activities Designation Regulation*[6] ("Activities Regulation") and the *Conservation and Reclamation Regulation*[7] ("Conservation Regulation"), all of which can be summarized as follows.

— **Agricultural Lands.** The AUC was directed to take an "agriculture first" approach when evaluating proposals for renewable development, ensuring that Alberta's native grasslands, irrigable and productive lands will continue

2 Order-in-council (171/2023).
3 Order-in-council (172/2023).
4 Alta Reg 108/2023.
5 Alta Reg 203/2024.
6 Alta Reg 276/2003.
7 Order-in-council (369/2024).

to be available for agricultural production and not impacted by future renewable electricity generation projects. In support of this approach, the Province will no longer permit renewable generation developments on Class 1 and Class 2 lands, as classified by the Alberta Land Suitability Rating System,[8] unless a proponent can demonstrate the ability for both crops and/or livestock and renewable generations to co-exist. An irrigability assessment ("Irrigability Assessment") must be conducted by proponents and considered by the AUC. Under the Land Use Regulation, a proponent applying for the construction or operation of a power plant within the "White Area"[9] may be required to submit an Irrigability Assessment by the AUC.

— **Reclamation Security.** The Policy Guidance announced that the Province would implement the necessary policies and tools to ensure that for approvals issued on or after March 1, 2024, developers are responsible for end-of-life reclamation costs, and must post bonds or security to the Province in an amount determined by the Province. Pursuant to the amendments to the Activities Regulation and Conservation Regulation, consistent reclamation requirements are required across all forms of renewable energy operations. This includes mandatory reclamation security requirements as well as a mandatory security requirement for projects located on private lands. Through a mandatory security or bond, the developers of renewable projects will be responsible for reclamation costs. Such reclamation security will be provided directly to the province or may be negotiated with landowners where sufficient evidence has been provided to the AUC.

— **Protected Areas.** Pursuant to the Land Use and Assessment Regulation, "pristine viewscapes" are conserved through the establishment of buffer zones where new wind projects will no longer be permitted. Other developments proposed within the buffer zones could trigger the need for a visual impact assessment to be provided to the appropriate regulator for consideration. Any electricity development that is proposed within a visual impact assessment zone, as designated by the Province, will be required to submit a visual impact assessment prior to approval.

— **Crown Lands.** The Province will enable the development of renewable generation on Crown lands on a case-by-case basis. The Province intends to engage with stakeholders, including any impacted Indigenous parties, in a meaningful consultation process, to develop a policy framework for renewable generation on Crown land. Any resulting legislative changes are expected in late 2025.

— **Municipalities.** The AUC is in the process of implementing rule changes which would: (i) automatically grant municipalities the right to participate in AUC hearings; (ii) enable municipalities to be eligible to request cost recovery for participation and review; and (iii) permit municipalities the right to review rules related to municipal submission requirements while clarifying consultation requirements.

Update on Carbon Capture, Storage and Utilization ("CCUS")

In the summer of 2024, the **first Sequestration Lease Agreement** ("SLA") for CO_2 storage pursuant to the Province's competitive bid process for carbon storage hubs was signed among the Province, Shell and ATCO EnPower for the Atlas carbon storage hub. This was hailed as a historic agreement for CCUS development in Alberta and ultimately led to the release by the Province of the standard form SLA that other hub proponents will be required to sign as they advance their projects in Alberta[10].

While the Province continues down the path of encouraging the development of large-scale CCUS hubs, near the end of 2023 the Province released the application guidelines for Small-Scale and Remote Carbon Sequestration Tenure,[11] allowing CCUS projects outside of the hub model to the extent they meet the specified criteria, including that the requested lands cannot overlap with existing carbon sequestration agreements or grants of pore space (including areas of interest for hub proponents and conventional subsurface reservoir leases). Applicants must make the business case for why they need the carbon sequestration operation, describing the source of emissions and projected timeline for the project and providing a rational for why sequestration in a proposed hub is not viable (timeline, economics, distance etc.).

Update on Carbon Capture Incentive Program

The **Alberta Carbon Capture Incentive Program** (the "ACCIP") was further detailed by the Province in April 2024 and aims to support and accelerate the development of CCUS infrastructure. The ACCIP plays a critical role in Alberta's strategy to remain at the forefront of CCUS

8 Class 1 lands are those that have none to slight limitations to growth while Class 2 lands are those with slight limitations to growth. It is noted that Alberta has no Class 1 lands.
9 The "White Area" is the part of Alberta shown outlined and colored white on the map annexed to Ministerial Order 71/85.
10 It is noted that since the Shell/ATCO EnPower SLA has been signed, additional hub proponents who were approved by the Province have entered into SLAs.
11 Alberta, **Small-scale and remote carbon sequestration tenure: Application guidelines**, September 12, 2023.

development and environmental sustainability.

The ACCIP offers a 12% grant on new eligible CCUS capital costs. The grant is paid in three installments over three years, starting after the first year of operations. Importantly, the ACCIP will cover projects in various sectors, such as oil sands, oil and gas production, enhanced oil recovery, petrochemicals, power generation, manufacturing, and cement production.

The ACCIP is designed to complement federal incentives, particularly the federal CCUS Investment Tax Credit ("CCUS ITC"), which provides significant tax benefits for companies investing in CCUS technologies. Although the ACCIP will largely align with the CCUS ITC, it allows for some flexibility where the federal tax credit does not apply. For example, the ACCIP will support projects that result in the permanent sequestration of carbon dioxide ("CO_2"), which includes enhanced oil recovery production, which is explicitly an "ineligible use" under the CCUS ITC.

Eligible projects must be located in Alberta and focus on capturing, compressing, storing, or utilizing CO_2. These projects are retroactively eligible for costs incurred from January 1, 2022, in alignment with the CCUS ITC. However, projects that have received funding through Alberta's Petrochemical Incentives Program or other royalty regimes cannot claim duplicate benefits for the same expenses.

The ACCIP will be funded by Alberta's Technology Innovation and Emissions Reduction Fund, which is fuelled by companies purchasing carbon credits to meet emission targets. The total funding is expected to be between C$3.2 billion and C$5.3 billion through 2035.

KEY DEVELOPMENTS IN 2024

Developments in Alberta's Restructured Energy Market

Background

On August 2, 2023, the Province issued an order-in council[12] pursuant to which the AUC was ordered to inquire into and report to the MUA on the ongoing economic, orderly and efficient development and operation of electricity generation in Alberta.

On March 11, 2024, the MUA **directed** the AESO to commence drafting a technical design proposal for the REM. This directive was influenced by recommendations from the respective reports of the AESO[13] and the Market Surveillance Administrator ("MSA").[14] The AESO report revealed its preliminary plan for the REM and the chosen strategy designed to improve system reliability and affordability.

On July 3, 2024, the MUA issued a **direction letter** to the AESO regarding the government's policy decisions for advancing the design of the REM. Specifically, the AESO was directed to proceed with:

— the introduction of a mandatory day-ahead market;

— allowing the price of energy to be determined by the strategic offers of market participants, while using market mitigation to limit the potential for excessive exercise of market power;

— maintaining a province-wide uniform price for electricity; and

— maintaining the following components of the REM as outlined in the AESO's confidential advice to the MUA: "Security Constrained Economic Dispatch" shorter settlement intervals, a review of the price floor and ceiling as well as the co-optimization of energy and ancillary services.

The confirmation from the MUA regarding the policy direction for the design enabled the AESO to concentrate on the detailed aspects of the design, ensuring the development of a workable market.

The AESO strategically divided the REM into six focused workstreams to facilitate the development process: (1) Day-Ahead Market, (2) Pricing and Energy Reserve Market, (3) Intertie Participation, (4) Market Power Mitigation, (5) Dispatch Optimization, and (6) Shorter Settlements. For each workstream, the AESO released a detailed options paper. Each paper provided a number of options for each workstream within the guardrails of the Province's direction, which served as a starting point for consultation in the design sprints.

Design Sprints

Between September 10 and November 28, 2024, the AESO conducted a series of six intensive design sprints, spanning a total of 24 days and encompassing approximately 200 hours of stakeholder consultation. These interactive sessions were facilitated both in-person and virtually, ensuring broad accessibility and participation.

12 **Order-in-council (171/2023)**.
13 Alberta's Restructured Energy Market, **AESO Recommendation to the Minister of Affordability and Utilities**, January 31, 2024.
14 **Advice to support more effective competition in the electricity market: Interim action and an Enhanced Energy Market for Alberta**, December 21, 2023.

The workshops included comprehensive presentations from the AESO about design aspects, alongside analyses from third-party consultants. The sprints were structured to facilitate a continuous exchange of dialogue and to solicit ongoing feedback from participants.

Outcomes on the Workstreams

Following the first six REM Design Sprints, the AESO released the **High-Level Design** covering each element of the market design, incorporating stakeholder feedback from the design sprints. Stakeholder feedback on the High-Level Design can be provided to the AESO until January 27, 2025. As discussed in detail within the High-Level Design, the six key elements of the REM design are:

- New Day-Ahead Markets: Financial day-ahead market and physical day-ahead commitment (DAC) helps price discovery and meets reliability needs.
- New Reserve Products: New products support reliability attributes markets to balance real-time supply and demand.
- Dispatch to Manage Reliability: Better tools needs to manage increasingly complex system.
- Wide Price Range and Scarcity Pricing: Better values reliability attributes when needed most, without relying on large participant actions.
- Co-optimization: Minimizes operating reserve costs by allowing for one product to fulfill requirements for another.
- Market Power Mitigation: Ensures affordable outcomes for consumers by implementing safeguards against excessive market power.

Implementation

	How it will be implemented (based on high-level design)
New Day-Ahead Markets	— Day-Ahead financial market – cleared for demand choosing to participate (voluntary) — Supply must offer, strategic bidding (economic withholding) is permitted — AESO procures DAC to meet net load forecast, plus some uncertainty, from must offer qualified sources
New Reserve Products	— Technology neutral eligibility and qualified requirements — Dispatch automated through security constrained economic dispatch (SCED), with opportunity cost factored into prices — Creation of ramping new operating reserves
Dispatch to Manage Reliability	— New IT to complete SCED – factor system constraints and requirements into hourly day-ahead & 5-minute real-time scheduling — Uniform price set at an uncongested reference location — Congestion managed through bids from providers to access systems
Wider Price Range and Scarcity Pricing	— $3,000/MWh price cap, - $100/MWh price floor — Sloped administrative scarcity price curve to reflect increasing scarcity from the $800/MWh offer cap to $3000/MWh price cap
Co-optimization	— Energy and operating reserve prices set through offers co-optimization to achieve lowest total costs of delivery and signal scarcity value when running short
Market Power Mitigation	— Offer cap $800/MWh in real-time market — Secondary offer cap with parameters refinement to ensure adequate revenue generation while providing guardrails to protect consumers from excessive exercise of market power — Localized market power mitigation on offers in constrained in flow pockets

Source: **AESO REM Information Session Presentation** (December 12, 2024) (slide 16)

Additional Direction from the MAU and Implementation of REM

Additional direction from the MAU associated with the REM Market Design was provided on December 10, 2024. Within this **Letter**, the MAU directed the AESO to continue the REM technical design as outline in the July 3, 2024 Direction Letter subject to the following further decisions, the AESO will:

— Develop a market-based congestion management mechanism that recognizes incumbency, provides impacted generators with a means of managing the dispatch risk arising from congestion constraints, and considers the participation of controllable load and energy storage. Any revenue generated from this mechanism will be applied toward the cost of transmission projects prioritizing congested areas of the province.

— Continue to have robust engagement with stakeholders on the development of the Independent System Operator ("ISO") Rules that will implement the REM, while ensuring alignment with the Province's objectives of reliability, affordability, investability, economic efficiency, and sustainability.

— Develop an energy pricing framework in accordance with guidance that will be provided within legislation.

— Collaborate with an AUC-led initiative to implement 5-minute settlement for transmission-connected loads, generators and interties by 2032 and for all loads by 2040.

The Province is directing the AESO to continue developing the detailed design of the REM in consultation with stakeholders, with a view to finalizing the detailed REM design before the end of 2025. For the implementation of REM, the Province indicated it will bring forward necessary policy tools to allow the initial set of ISO Rules required for REM to be enacted via legislation. Under this approach, the initial REM rules will be enacted but not brought into effect before the end of 2025. The AESO will continue to work with stakeholders to develop an implementation plan to consider overall industry readiness for the market transition.

With implementation of the REM rules and the AESO new market systems infrastructure, an interim period will commence. It is intended that during this interim period, a mechanism will be provided for the AESO to correct possible technical deficiencies with the REM rules in an expeditious manner. The new market would then operated for a period of time before the interim period comes to an end.

At the end of the interim period and beyond, any proposed amendments to the REM rules will require AUC approval in accordance with established process for ISO Rules.

Update on Transmission Policy Review

Further to the reforms outlined in the Province's July 3, 2024 **direction letter**, the Province, in a further **direction letter** issued on December 10, 2024, announced additional guidance to the AESO's responsibilities for planning the transmission system and developing the ISO tariff. The guidance includes the following:

— Implement a cost allocation framework for new transmission infrastructure based on cost-causation principles by requiring new generators to contribute to transmission infrastructure costs by replacing the Generating Unit Owner's Contribution with an upfront non-refundable Transmission Reinforcement Payment ("TRP").

  — These payments will have a floor of $0/megawatt and no upper limit and are intended to apply to both transmission-connected and distribution-connected generators.

  — TRP rates will be calculated as a function of the suppliers' proximity to the transmission capacity, their technical attributes and characteristics, and the cost of reinforcing the transmission system.

— Recover line losses through a system-wide average starting on January 1, 2027.

— The AESO will be required to do the following:

  — file a needs identification document for the Alberta Intertie Restoration Project by December 31, 2026, to restore the Alberta-British Columbia intertie to or near to 950 megawatts;

  — procure and maintain high levels of ancillary services to support full import flows on the Alberta-British Columbia intertie and the Montana Alberta Tie Line;

  — increase the path rating of the Alberta-Saskatchewan Intertie as part of the McNeill Converter's end-of-life replacement to leverage the existing transmission capacity in the region; and

  — remove the competitive procurement requirement for upgrades or enhancements to the path rating of interties.

In order to implement other transmission policy changes, with a view to expeditious implementation, the Province also directed the AESO to commence stakeholder consultation.

Bill 18 (Provincial Priorities Act)

On April 10, 2024, the Province introduced Bill 18, known as the *Provincial Priorities Act*[15] ("Priorities Act"), with the stated goal of ensuring that agreements made with the federal government align with the Province's strategic goals and financial commitments at all times.

The Priorities Act received royal assent on May 30, 2024, and is anticipated to come into force in early 2025, once the regulations are finalized. Currently, the detailed procedures for obtaining the requisite provincial approval and any exemptions are unknown. The Priorities Act will apply to intergovernmental agreements entered into by "provincial entities" (e.g., municipalities, public post-secondary institutions and Crown-controlled organizations) but will not apply retroactively to existing agreements or projects. However, it appears that the Priorities Act will apply to any amendments, extensions and renewals of these pre-existing agreements. Going forward, prior to initiating, amending, extending, or renewing any intergovernmental agreement with federal government entities, "provincial entities" will need to secure advance approval from the Province. Failure to obtain such Provincial approval purports to have the effect of deeming the subject agreement invalid and of no force and effect.

Altius Royalty Corporation v. Alberta

On April 4, 2024, the Alberta Court of Appeal (the "Court") released a judgment in *Altius Royalty Corporation v. Alberta*[16] ("*Altius*"), clarifying how constructive expropriation applies to the Province's plan to phase out coal-fired electricity generation emissions by 2030. Altius Royalty Corporation, Genesee Royalty Limited Partnership and Genesee Royalty GP Inc. (collectively, the "Appellants") held royalty interests in the Genesee coal mine, which fuels the Genesee power plant that provides energy to the City of Edmonton. The Government of Canada and the Province (the "Respondents"), respectively, introduced legislation to phase out coal-fired electrical generation and entered into off-coal agreements ("Off-Coal Agreements") with owners of coal-fired power plants to end this type of higher emissions generation. The Appellants argued that the Respondent's legislation and Off-Coal Agreements amounted to constructive expropriation since it precluded their ability to receive royalties from their interest in the mine post-2030. The test for constructive appropriation requiring compensation, requires: (1) an acquisition of a beneficial interest in the property or flowing from it (an "advantage"); and (2) removal of all reasonable uses of the property.

The Court concluded that for constructive expropriation to occur, the interest allegedly being expropriated must be sufficiently proprietary such that it can be acquired, and that there must be some correspondence between the expropriated interests and the acquired interest. The Appellants argued that the advantage flowing to the Respondents is a reduction in healthcare and environmental expenses, and that since a dollar amount can be attributed to these expenses, the advantage is proprietary. The Court ruled that a generalized public benefit cannot constitute an advantage flowing to the Crown in satisfaction of the constructive expropriation test. As a result, the Court did not consider the second step of the test.

The Government of Canada's public policy goal behind the regulation of coal-fired electricity generation was not an advantage regarding private property accruing to the Crown. Further, the loss of royalties sustained by the Appellants was a result of the owners of coal-fired generation plants' decision to cease operations in light of their private Off-Coal Agreements with the Province, not constructive expropriation.

In conclusion, the Court clarified that it will not expand the interpretation of the constructive expropriation test to include situations where regulations impact royalty interests in the Province's energy sector. The decision in *Altius* suggests that the parties alleging constructive expropriation of coal royalties in response to anti-coal legislation or Off-Coal Agreements may face judicial resistance.

15 **SA 2024, c P-35.5**.
16 **2024 ABCA 105**.

REGULATORY UPDATES

AUC Rule 007 Updates

Updates to AUC application review process following Renewables Pause

As previously noted, the Renewables Pause, which prevented the AUC from issuing approvals for new power plants and hydro developments producing renewable electricity over 1 megawatt, expired on February 29, 2024. Since March 1, 2024, the AUC resumed issuing decisions on affected power plant applications.

Enhanced interim information requirements

In September 2023, the AUC introduced **interim information requirements** for new power plant applications (wind, solar, thermal, hydroelectric, and others), covering agricultural land, viewscapes, reclamation security and municipal land use. Based on stakeholder feedback and guidance from the Province, the AUC will continue using these requirements, with the following additional details on reclamation security:

1. A third-party report estimating reclamation costs, including the salvage value of project components; and
2. An explanation of the chosen form of security, its attributes, and how the secured party can realize on the security if the project defaults.

New power plant and energy storage facility applications filed after May 2, 2024, must meet both the existing requirements of Rule 007 and these enhanced interim requirements. Moving forward, it is important to note that the rules are still being finalized, and ongoing public consultations will shape the final outcomes. The interim information requirements are in effect until further notice.

Additional amendments came into force on March 28, 2024, clarifying requirements involving the lifespan of energy storage facilities and exemptions from filing applications for small power plants, small energy storage facilities and isolated generating units, as follows:

— **Energy Storage Facility:** Information required for amending, decommissioning and salvaging, cancelling or extending the construction completion date of an energy storage facility has been added in a separate section.

— **Exemptions from Filing Applications:** Owners of small power plants, small energy storage facilities, and isolated generating units are exempt from filing an AUC application if the construction or operation of small power plants, small energy storage facilities and isolated generating units: (i) does not directly and adversely affect any person; (ii) does not have an adverse environmental impact; and (iii) meets the requirements of AUC Rule 012: *Noise Control*.

Land Use and Assessment Regulation

As further discussed in the **Environmental Law** chapter of this publication, the Land Use and Visual Assessment Regulation generally applies to applications for the construction or operation of Power Plants[17] under Rule 007, provided however the Land Use and Visual Assessment Regulation does not apply to the following: (a) the construction or operation of (i) small Power Plants, (ii) isolated generating units, and (iii) micro-generation generating units; (b) the construction or operation of a Power Plant situated on a reserve; and (c) alterations to an existing Power Plant approval issued by the AUC.

The Land Use and Visual Assessment Regulation imposes obligations on proponents to three broad areas for renewable energy developments:

— **Agricultural Land Use:** Proponents applying for construction or operation of a wind plant or solar power plant on privately owned "high-quality agricultural land" will be required to submit an "agricultural impact assessment" as part of their application detailing the effects of the plant on agricultural productivity and that includes measures demonstrating that the plant is designed to "coexist" with agricultural operations and land use, including both crops and/or livestock.

— **Irrigability Assessment:** Proponents applying for construction or operation of a Power Plant within the "White Area" may be required to submit an Irrigability Assessment to the AUC, which may include: (a) an evaluation of water quality and availability; (b) an analysis of proximity to irrigation infrastructure; (c) the economic viability or feasibility of irrigation; and (d) the opinions of the applicable irrigation district.

— **Buffer Zones and Visual Impact Assessment Zones:** To ensure that "pristine viewscapes" are conserved, the AUC will no longer accept any applications under Rule 007 for the construction or operation of a

17 Pursuant to the Land Use and Visual Assessment Regulation, a "Power Plant" is defined as the facilities for generating and gathering electric energy from any source.

wind power plant in a buffer zone, as described in a schedule to the Land Use and Assessment Regulation. A proponent applying for construction or operation of a Power Plant within a buffer zone must submit a "visual impact assessment" which may include: (a) an evaluation of the anticipated visual impacts on the buffer zone; (b) visual simulations from key vantage points illustrating the potential visual impact on the proposed Power Plant; and (c) proposed mitigation measures to minimize or offset any adverse visual effects on the buffer zone.

The Land Use and Visual Assessment Regulation is set to expire on December 31, 2029, as a measure to ensure that it is reviewed for ongoing relevancy and necessity.

Conservation and Reclamation Amendment Regulation

The **Amended Reclamation Regulation**, enacted under the ***Environmental Protection and Enhancement Act*** (EPEA), revises the existing ***Conservation and Reclamation Regulation***. The Amended Reclamation Regulation updates the existing regulatory framework for wind and solar power plants:

1. **New Code**: The Amended Reclamation Regulation introduces the Code of Practice for Solar and Wind Renewable Energy Operations (the Code). Those carrying on the construction, operation or reclamation of a "solar electric renewable energy operation" or "wind electric renewable energy operation" (the "Specified Activities") are required to comply with the Code.

   The Code will apply if (i) the total footprint of the operation is greater than one hectare, or (ii) the amount of electricity generated from the operation is greater than the maximum amount permitted for a large micro-generation as specified in the Micro-generation Regulation, but does not include an operation that is operated by a person solely on property of which that person is the owner, for use solely by that person and solely on that property.

2. **Imposing Security Obligations**: An operator must provide security with respect to a registration for a Specified Activity, prior to the registration being issued. The exact requirements for the type, timing, and amount of the security, according to the Code, have not been made public yet. However, the security provided must comply with the acceptable forms outlined in the Conservation and Reclamation Regulation. These forms include cash, cheque, government bond, an irrevocable letter of credit, a performance bond, or any other form that the Director approves.

3. **Exemption from Security Obligations**: An operator is exempt from security obligations if it applies for registration of the Specified Activity under EPEA and provides security to a registered owner of the land under a surface lease.

The Amended Reclamation Regulation states that proponents who were already engaged in the construction, operation, or reclamation of a solar or wind renewable energy operation prior to the amendments taking effect on January 1, 2025, are permitted to continue these activities without obtaining a registration for that activity under the EPEA until January 1, 2027.

AUC/ISO RULE CHANGES

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

Agency	Rule	Summary
AUC	Rule 022 – *Rules on Costs in Utility Rates Proceedings*	The AUC announced amendments to Rule 022 in **Bulletin 2024-02**. The amendments came into force on March 1, 2024 and include: — expanding the eligibility for cost recovery to applicants and eligible interveners, as well as partial cost recovery for rural electrification associations, municipalities and other previously ineligible participants if they intend to file expert or other evidence or argument that will assist the AUC in understanding issues material to the proceeding and would not otherwise be presented to the AUC; — streamlined application forms available electronically, ensuring all cost applications are consistent and eliminating previous requirements such as the need to file an affidavit in support of the claim; and — an updated scale of costs reflecting increased hourly rates for lawyers, consultants and experts.
AUC	Rule 009 – *Rules on Local Intervener Costs*	The AUC announced amendments to Rule 009 in **Bulletin 2024-02**. The amendments came into force on March 1, 2024, and include: — an updated scale of costs to align with the scale of costs for Rule 022; — extending the availability of travel expenses to site visits in addition to hearing attendance; and — slightly modified language to refer to a new cost application form. The AUC intends to commence stakeholder engagement on more fulsome changes to Rule 009.
AUC	Rule 015 – *Rules on Costs of Investigations, Hearings or Other Proceedings Relating to Contraventions*	The AUC announced amendments to Rule 015 in **Bulletin 2024-11**. The amendments came into force August 1, 2024, allowing both AUC Enforcement and the MSA to recover costs: — on a fully burdened basis (including overhead costs) of staff investigating and prosecuting conventions; and — on a full indemnity basis of external consultants and legal counsel engaged by AUC Enforcement or the MSA when investigating and prosecuting contraventions.
AUC	Rule 32 – *Specific Penalties*	The AUC provided a notification of change approving the amendments to Rule 032 in **Bulletin 2024-15**. The amendments increased penalties for non-compliance, increased credit given to those who self-report (increasing

Agency	Rule	Summary
		from 50% to 80%), and now allow specified penalties to be imposed for contraventions of certain sections of Rule 001: *Rules of Practice*, Rule 012: *Noise Control* and in respect of certain decisions and orders made by the AUC under the *Hydro and Electric Energy Act*,[18] the *Pipeline Act*[19] and the *Public Utilities Act*.[20]
AUC	Rule 029 – *Municipal Franchise Agreements*	The *Utilities Affordability Statutes Amendment Act, 2024*[21] ("UASAA") made several changes to statutes concerning franchise agreements that came into force on June 20, 2024. As a result, any franchise agreement impacted by the amendments will terminate on March 17, 2025, unless approved by the AUC before this date. In **Bulletin 2024-18**, the AUC announced amendments to Rule 029 that came into force September 12, 2024. The amendments are intended to enable the legislative changes found in the UASAA by modernizing the notice requirements and clarifying language. The revised rule adds a minimum notice period for franchise agreement applications of 45 days.
AUC	Rule 018 – *Settlement Issues and Interim Change*	The AUC has prepared draft amendments to Rule 018 in **Bulletin 2024-19**. The proposed amendments are intended to make settlements more accessible and efficient. One material change that the AUC has proposed is to rescind Rule 018 and incorporate the amendments as provisions in Rule 001, which would outline the steps necessary to commence a negotiated settlement process and specify the information that must be included in a settlement agreement prior to filing. Additionally, between September 13, 2024 to October 25, 2024, the AUC sought stakeholder feedback on two issues: — the potential for AUC-led mediations; and — enhanced AUC staff participation in negotiated settlement processes.
AESO	**ISO Rule 206.1** – *Interim Secondary Offer Cap*	The new ISO Rule 206.1 was added to support the *Market Power Mitigation Regulation*,[22] which implemented a secondary offer cap on thermal offers of market participants with a 5% or greater market share once a certain net revenue threshold has been reached in a month, which became effective July 1, 2024. ISO Rule 206.1 requires the ISO to calculate Monthly Cumulative Settlement Interval Net Revenue and to enforce a secondary offer cap when interval net revenue of the reference generating unit revenue exceeds certain limits. The AESO has developed three new Energy Trading System reports designed to present information on these calculations and caps. Subsection 2 regulates the secondary offer cap price limit, imposing obligations on pool participants with offers for any settlement intervals upon notification from the ISO.

18 RSA 2000, c H-16.
19 RSA 2000, c P-15.
20 RSA 2000, c P-45.
21 SA 2024, c 8.
22 Alta Reg 43/2024.

Agency	Rule	Summary
AESO	**ISO Rule 206.2** *– Interim Supply Cushion Directives*	The new ISO Rule 206.2 was added to align with the *Supply Cushion Regulation*[23] ("SCR"), which became effective July 1, 2024. The stated purpose of the supply cushion is to ensure reliability by maintaining an appropriate reserve margin of supply adequacy for the interconnected electric system. This rule is intended to enhance the SCR by: — establishing clear guidelines for pool participants with eligible long lead time assets to submit their projected operational costs and physical limitations; — requiring the AESO to transparently communicate the methodology it employs to estimate the supply cushion; and — setting forth the procedures for pool participants to report the actual costs resulting from compliance with unit commitment directives. This process will also include the stipulation for a cost attestation to qualify for a cost guarantee.
AESO	**ISO Rule 205.9** *– Fast Frequency Response*	New ISO Rule 205.9 has been added to regulate the provisions of fast frequency response services by market participants and the ISO. Market participants are now required to: — provide real-time data to the ISO via systems designated by ISO; — comply with dispatches to arm or disarm the service in accordance with the contract; and — respond to frequency drop by adjusting power flow when the service is armed. If there is insufficient service, the ISO may adjust import transfer levels and potential contingencies accordingly. Additionally, market participants cannot use the same capacity for both fast frequency response service and operating reserves simultaneously
AESO	**ISO Rule 205.10** *– Dispatches for Concurrent Services*	The new ISO Rule 205.10 provides clarity to pool participants regarding the hierarchy of importance for competing dispatches or directives. If a pool participant is under multiple dispatches, it must prioritize the provision of services in the order of: — transmission must-run; — operating reserve; — fast frequency response service; and then — dispatch down service.

23 Alta Reg 42/2024.

Agency	Rule	Summary
AUC	ISO Rule 202.3 – *Issuing Dispatches for Equal Prices*	Subsection 2 was amended to require the ISO to issue dispatches for all of the equally-priced offers first, followed by dispatches for all of the equally priced bids. Subsection 2(4), previously 2(3), was amended to change the procedures used to determine dispatch volumes for a pool asset that is an import or export asset to those set out in Section 203.6 of the ISO Rules, *Available Transfer Capability and Transfer Path Management*, rather than those set out in Operating Policy and Procedure ("OPP") 301 and OPP 302.

AMENDMENTS TO THE *HYDRO AND ELECTRIC ENERGY ACT*

The ***Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act***[24] ("ESAA"), originally Bill 22, was proclaimed in March 2024 after nearly two years of regulatory development. The ESAA amends key legislation, such as the ***Alberta Utilities Commission Act***,[25] the ***Electric Utilities Act***[26] and the ***Hydro and Electric Energy Act***.[27] These changes are significant as they facilitate the integration of new technologies, including energy storage, and modernize Alberta's electricity infrastructure. Key changes under the ESAA include:

1. energy storage integration;
2. enhanced transmission and distribution planning;
3. clarification on self-supply and export; and
4. winding down of the Balancing Pool.

The ESAA represents a significant advancement in the Province's approach to integrating energy storage into its power grid. Before the ESAA, there was uncertainty about how these facilities would be regulated. By formalizing the application process, the ESAA addresses a longstanding regulatory gap that left energy storage facilities in a gray area between generation and transmission services. Now, investors and developers can proceed with greater confidence knowing that there are clear pathways for energy storage, encouraging innovation and expansion in this sector.

The ESAA's provisions allowing the AESO to procure "non-wires services," including energy storage solutions, is a shift that enhances the flexibility and cost-effectiveness of Alberta's energy grid. By enabling the AESO to use energy storage and other non-wires alternatives under Section 25.1, the ESAA provides a broader toolkit for managing grid demand and alleviating transmission constraints without defaulting to costly new infrastructure investments.

The ESAA's provisions on self-supply and the export of excess electricity mark a critical step toward supporting industrial generators across Alberta. Previously, regulatory ambiguity created significant barriers for industries looking to generate their own power, especially if they wished to sell any surplus back to the grid. The ESAA clarifies these parameters, setting specific conditions under which generators can self-supply and export excess power, opening up new operational and financial opportunities across diverse sectors.

The ESAA's winding down of the Balancing Pool marks the end of an era for Alberta's electricity market. Established to manage Power Purchase Arrangements ("Arrangements") and stabilize the Market following the deregulation of electricity in Alberta, the Balancing Pool's primary role was to hold and manage any unclaimed Arrangements, handle associated risks, and manage surplus funds for consumer benefit. However, with the expiration of these Arrangements in 2020, the Balancing Pool's core responsibilities effectively became redundant, prompting the move toward its closure by January 2025. This transition is part of Alberta's broader strategy to streamline the regulatory and operational structures in its electricity market.

Ultimately, the ESAA's clear regulatory framework is anticipated to foster a robust energy storage market in Alberta. This will enhance grid efficiency, reduce costs, and support the Province's shift towards a more sustainable and resilient energy future.

24 2022, SA 2022, c 8.
25 SA 2007, c A-37.2.
26 SA 2003, c E-5.1.
27 RSA 2000, c H-16.

ALBERTA ENERGY REGULATOR ("AER") RULE UPDATES

Rule	Summary
Directive 050: Drilling Waste Management ("Directive 050")	The recent updates to Directive 050 apply to drilling waste management requirements for brine-hosted mineral developments aligned with the latest edition of the Government of Alberta's *Alberta Tier 1 Soil and Groundwater Remediation Guidelines*.[28] Directive 050 outlines the soil endpoints for salts, hydrocarbon and metal and the suitable soil horizon and rating categories for each drilling waste disposal method and acceptable initial soil and final soil-waste salinity endpoints. Alteration of a drilling waste management method set out in Directive 050, or the use of a method not prescribed in this directive, such as biodegradation or subsurface, requires prior approval from the AER. This release aims to ensure that licensees meet the AER requirements and environmental outcomes through monitoring and reporting.
Directive 065: Resources Applications for Oil and Gas Reservoirs ("Directive 065")	Directive 065 sets out the application requirements for most conventional oil and gas reservoir topics considered in an application for AER approval. Recent updates introduced requirements around induced seismicity for fluid disposal activities. Directive 065 amended the requirements for acid gas disposal and containment assurance and CCUS and updated the application process. The two-step application process (resource application and well spacing application) now applies to all enhanced recovery, disposal, and CO_2 sequestration schemes. Notification requirements have been expanded and now mandate that disposal applicants notify Crown agreement holders. Directive 065 adds that applications for CO_2 sequestration schemes, also referred to as CCUS projects, must establish a site-specific risk assessment, baseline conditions for monitoring, and strategies for remediation in case of containment loss. For small-scale or remote sequestration projects, dynamic simulation models are not mandatory.
Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals ("Directive 067")	Directive 067 was released in March 2024 and sets out requirements for applying for, maintaining, and amending a licence for energy development in Alberta, including the necessary permitting for CCUS project development and operation. It also identifies the circumstances in which the AER may revoke or restrict licence eligibility. These circumstances include: failure to provide complete, accurate, and timely required information; a finding by the AER that the licensee or approval holder poses an unreasonable risk; and the failure of the licensee to obtain or hold licences or approvals within one year after receiving licence eligibility.
Specified Enactment Direction 002: Application Submission Requirements and Guidance for Reclamation Certificates for Well Sites and Associated Facilities ("SED 002")	SED 002 was amended to apply to all energy resource developments regulated by the AER: oil and gas, geothermal, and brine-hosted mineral resource development. SED 002 sets out the information requirements for reclamation certificate applications for energy resource development and brine-hosted-mineral resource development, including associated facilities and pipelines under the *Environmental Protection and Enhancement Act*[29] ("EPEA"). SED 002 also provides guidance on how to comply with these requirements. Under EPEA, operators must apply for a reclamation certificate after an energy resource development facility (e.g., well site, battery, gas plant, pipeline, borrow pit, temporary workspace, geothermal facility) or mineral resource development facility has been decommissioned and abandoned.

28 *Alberta Tier 1 Soil and Groundwater Remediation Guidelines*, Lands Policy, 2024, No. 1.
29 RSA 2000, c E-12.

Follow-up on AUC Decision 27084-D02-2023

On October 9, 2023, the AUC released **Decision 27084-D02-2023**,[30] adopting a formula-based approach to establish the rate of return on equity ("ROE") for Alberta's regulated electric and natural gas utilities for 2024 and beyond. The AUC also established deemed equity ratios, defining the debt-to-equity ratios for these utilities' capital structures. Together, these factors influence the profitability of each regulated utility.

The deemed equity ratio was determined to be 37% for all distribution and transmission utilities, except for Apex Utilities, which received a ratio of 39%.

This approach, known as the generic cost of capital ("GCOC"), applies to all regulated electric and natural gas utilities, aiming to reduce regulatory lag, and create a more efficient, predictable and cost-effective regulatory process.

The AUC formula will use an equity risk premium approach by incorporating 30-year Government of Canada bond yields and utility bond yield spread. The ROE for 2024 was calculated by the AUC to be 9.28% for all utilities.

The AUC will conduct a mandatory review of cost-of-capital parameters every five years, subject to mid-term reopeners either at its own discretion or upon application from interested parties. The established cost-of-capital parameters apply to:

— AltaLink Management Ltd.

— Apex Utilities Inc.

— ATCO Electric Ltd.

— ATCO Gas and Pipelines Ltd.

— ENMAX Power Corporation

— EPCOR Distribution & Transmission Inc.

— Fortis Alberta Inc.

— Kainai Link L.P.

— City of Lethbridge

— PiikaniLink L.P.

— The City of Red Deer

— TransAlta Corporation

The cost-of-capital parameters for the various investor-owned water utilities under the AUC's jurisdiction were not determined in this proceeding. However, the determinations in this proceeding may be considered in other proceedings should issues respecting ROE and deemed equity ratios arise for these utilities.

What's Next?

In recent years, the regulatory framework governing Alberta's energy market has undergone significant modification, re-evaluation and advancement with the Province mandating a number of reviews of the existing market, regulatory environment and energy infrastructure, and this trend is expected to continue into 2025. In particular, as the REM review nears its conclusion, it is anticipated that this review will prompt a further series of regulatory reform and industry changes in Alberta and that the REM's influence will also extend to the construction and development of expanded infrastructure to support the shift in the energy market.

We anticipate 2025 will bring substantial investment in Alberta's infrastructure with the aim of bolstering the energy sector and the reliability of Alberta's electricity grid. These investments are likely to include construction of new pipelines, an evaluation of Alberta's existing transmission lines and the implementation of advanced energy distribution and storage networks. This includes an assessment and modernization of Alberta's existing intertie system, which plays a crucial role in connecting Alberta's electricity network with neighbouring regions. Investment in Alberta's infrastructure will be necessary to meet the Province's current energy demands, but also to prepare the grid to handle future demand and reliability challenges, including the continued integration of renewable energy sources and evolving consumption patterns.

30 **AUC Decision 27084-D02-2023**, Determination of the Cost-of-Capital Parameters in 2024 and Beyond (October 9, 2023).

QUÉBEC REGIONAL OVERVIEW

By Julie Belley-Perron, Louis-Nicolas Boulanger, Elena Sophie Drouin, Kim Godbout, Mathieu LeBlanc, Jason Phelan, Alexandre Saulnier-Marceau and Jacob Stone

Québec Regional Overview

Heightened activity in Québec's power sector continued throughout 2024, driven in part by the projects in development as result of the 2021 and 2023 wind and other renewables request for proposals, and recent strategies and action plans to address increased demand for electricity and disappearing energy surpluses. Plans to revamp the provincial legislative framework for energy through draft Bill 69 were heavily debated as they could introduce fundamental changes to how energy is planned, procured, supplied and distributed in Québec.

FIRST SOLAR CALL FOR TENDERS

The year 2024 in Québec was marked by the first solar energy call for tenders of this province (the "RFP"). **Currently, there are no significant solar power projects that have been developed or that are under development** in the province and solar power accounts for a modest 22 megawatts ("MW") of total energy production capacity in Québec.

Framework of the RFP

On March 26, 2024, the Québec Government **announced** a block of 300 MW would be reserved for an upcoming solar energy procurement by Hydro-Québec, but it was only in September 2024 that the main requirements for this RFP were made public. The official launch of this solar RFP confirms the Québec government's interest in laying the foundations for a Québec solar industry.

Hydro-Québec is to hold two calls for tenders, the first to be launched no later than on **December 31, 2024** for a minimum of 150 MW, and the other to be launched no later than on **December 31, 2026** for the remaining balance. In addition, all 300 MW procured must be interconnected to the Hydro-Québec grid by **December 31, 2029**.

To manage the variable production output of solar energy, the RFP indicates that solar energy production will be supported by a balancing and supplementary power service, in the form of an energy integration agreement for variable energy which would be secured with either Hydro-Québec or another energy producer in Québec.

Next Steps

A stated goal for the RFP is to favour the development of local energy sources and reduce reliance on Hydro-Québec's transmission network. To that end, preliminary guidelines were shared by the Québec Government in respect of the economic, environmental and social impacts of the RFP in a **second order-in-council, published on September 25, 2024**. These include:

- Priority will be given to projects built on brownfield lands (i.e., lands with pre-existing uses), with electricity generation being a secondary use, unless the project aims to revitalize an underused area.
- Similar to past wind energy call for tenders, projects will be expected to maximize Québec content and to encourage partnerships with local municipalities, communities, and Indigenous groups.

The deadline for submitting bids to Hydro-Québec had not yet been announced at the time of drafting of this overview.

REVAMP OF QUÉBEC'S ELECTRICITY REGULATORY FRAMEWORK

On June 6, 2024, the Government of Québec's Economy, Innovation and Energy Minister tabled a much-anticipated new bill ("Bill 69") aimed at providing the Province of Québec with the tools and means to achieve its energy transition. Titled "***An Act to ensure the responsible governance of energy resources and to amend various legislative provisions***," the primary objective of Bill 69 is to speed up green energy production in the Province, with the ambition of making Québec the first carbon-neutral jurisdiction in North America. Although electricity appears to be at the centre of Bill 69, some changes are also directed at natural gas production and regulation, as well as other sectors of the energy supply chain of the Province.

According to current strategies and plans, Québec needs to double its current energy production by 2050 to support initiatives that will allow it to reach its climate targets and support industrial development in the Province. Among some of the key changes introduced, Bill 69 contemplates (i) an important reform of Québec's energy governance model, (ii) new electricity distribution rules, and (iii) additional flexibility for Hydro-Québec to spur energy project development.

Energy Governance and Planning

Bill 69 seeks to change the energy governance framework in Québec by increasing governmental oversight in the development of a long-term vision for the production of energy that meets the increasing demand.

Bill 69 gives the Québec Economy, Innovation and Energy Ministry a central role in the energy industry. The Energy Minister would be responsible for creating by 2026, and then updating every six years, a 25-year integrated energy resource management plan for the Province. This integrated plan will need to align with existing governmental orientations with respect to economic development, energy transition and sustainable development. Supply plans for electricity and natural gas distributors would in turn need to align with this plan.

Other changes in Bill 69 look to update the structure and mission of the *Régie de l'énergie* (the "Energy Board"), the regulatory body in charge of overseeing energy related matters in the Province. Bill 69 would notably amend the Energy Board's mission to include the specific goals of ensuring and securing sufficient, safe, reliable and cost-effective electricity supply to meet both Québec's market needs generally, and the targets set by the integrated energy resource management plan specifically. It would further be required to maximize the economic, social and environmental benefits of energy regulation in the Province.

Electricity Distribution Rules

Under existing regulations, only Hydro-Québec and a limited number of municipal, cooperative and private distributors holding legacy rights over specific portions of the territory of the Province are currently authorized to sell and distribute electricity to consumers. Bill 69 would create an exception to Hydro-Québec's quasi-exclusive monopoly over electricity distribution by authorizing a renewable energy producer to sell and distribute electricity to a single private customer located on an adjacent site, for the needs of its installations, but subject to obtaining an approval from the Québec government.

While this proposed change would not create as much flexibility as some were initially hoping, mainly because reliance on this exception in all cases requires governmental approval which would be discretionary in nature, the direct sale of electricity between private parties would now become possible. As currently drafted, Bill 69

does not provide a clear definition for key terms of this new regime, such as the scope of what is understood to be “renewable energy” or an “adjacent site.” The exact scope of this new exception could be clarified during parliamentary debates, although some expect that the government may refrain from doing so in order to retain maximum flexibility to authorize direct sale initiatives which align with governmental objectives.

A More Flexible Approach to Renewable Project Development and Procurement

A number of amendments included in Bill 69 are aimed at providing Hydro-Québec with additional flexibility to initiate energy project development and to procure energy for the Province. Under these changes, the existing public procurement tendering process in respect of renewable energy, managed by Hydro-Québec, would no longer require the approval by the Energy Board of its terms and conditions. This should help accelerate the launch of requests for proposals for new power supplies. The Government of Québec would nevertheless continue to have the power to compel Hydro-Québec to procure energy pursuant to requests for proposals and on terms determined by the government. In addition, the instances in which the Energy Board would be required to approve power purchase agreements awarded by Hydro-Québec would be narrowed. Regulations to come would set out cases in which an Energy Board approval is required, but in any event no approval would be needed for any power purchase agreement awarded pursuant to a request for proposals which allows for the fair treatment of bidders, in case of emergency, for short-term agreements of a duration of up to three months or in other cases approved by the government.

Next Steps

Bill 69 was adopted in principle in October 2024. It will now undergo a detailed study by a commission of the National Assembly which is expected to commence in the first few months of 2025, and it should be sanctioned later in 2025. Once made into law, Bill 69 would represent one of the most important reforms to the Province’s energy regime since the nationalization of electricity in 1962.

HYDRO-QUÉBEC’S NEW STRATEGY FOR LARGE-SCALE WIND ENERGY DEVELOPMENT IN QUÉBEC

In May 2024, Hydro-Québec presented its much anticipated **Wind power development strategy**. The strategy is part of its larger **2035 Action Plan** which was issued in November 2023 and laid out an ambitious energy transition strategy leading to decarbonization. The 2035 Action Plan emphasized that wind power is a crucial element in Hydro-Québec’s strategy to meet its 2035 objectives, which include increasing its renewable energy capacity to generate over 10,000 MW of new wind power by 2035. This requires the annual deployment of 1,000 to 1,500 MW of additional capacity. In comparison, over a 20-year span from 2000 to 2020, 44 wind farms with a total installed capacity of around 4,000 MW were commissioned in Québec, for an annual pace of deployment of new power generation of about 200 MW per year. Adding 10,000 MW of new wind power capacity represents over C$30 billion in private and public investments.

As part of the consultations relating to the 2035 Action Plan, the results of which were summarized in a **report** published in June 2024, Hydro-Québec met with various stakeholders, including municipalities, First Nations representatives, as well as environmental, business and consumer interest groups. Concerns were expressed as to the current development model of wind power in Québec, notably in terms of planning and coordinated approach. The need for greater collaboration with local communities and First Nations was also highlighted. In response to such concerns, Hydro-Québec is redefining its development model for large-scale wind power by confirming that it will play a pivotal role as the *maître d’oeuvre* of such projects from now on. Hydro-Québec also committed to adopting a community partnership approach to developing wind power projects so that First Nations and municipalities may become shareholders in those projects.

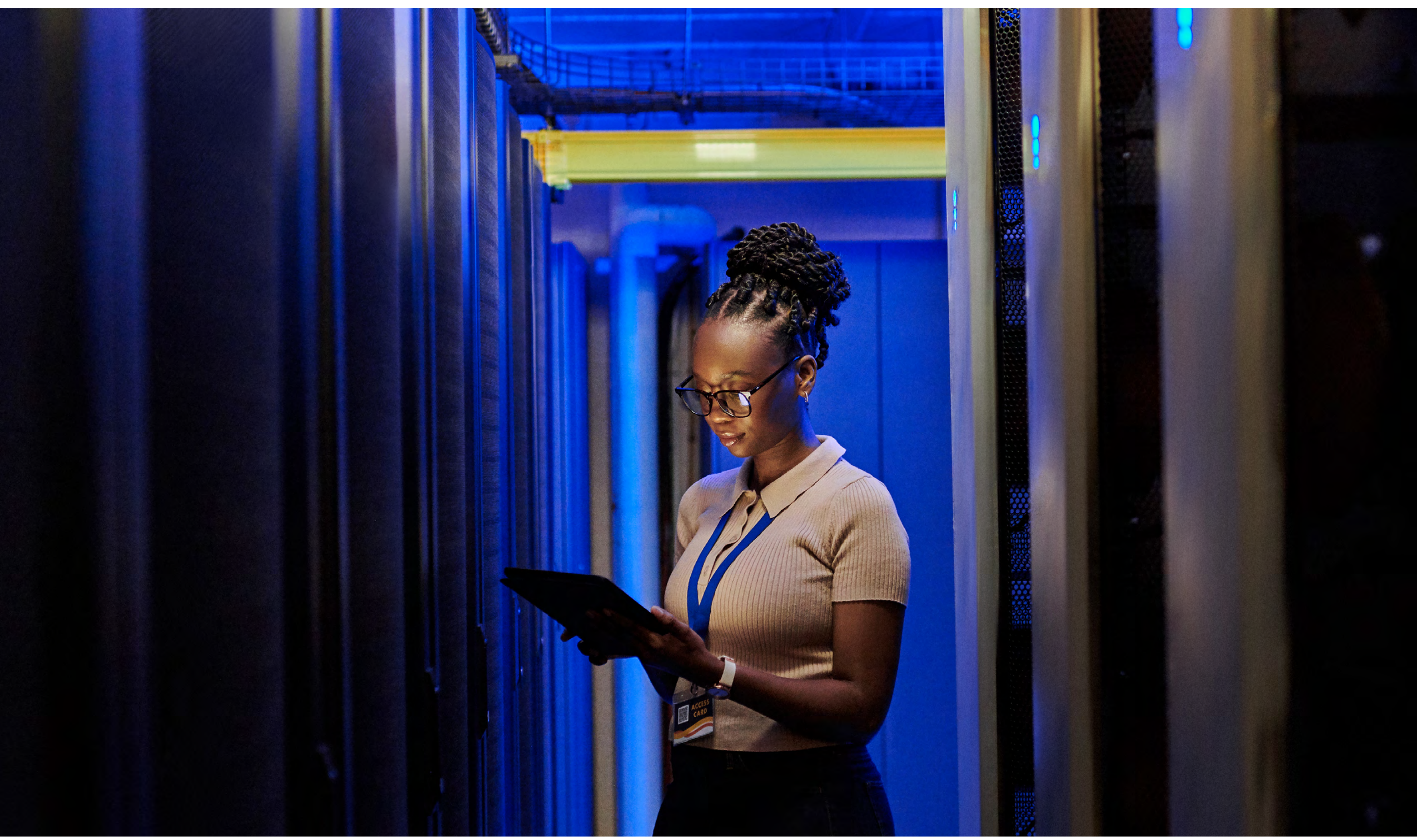
A New Development Model

The main component of Hydro-Québec's new model of wind power development of is that Hydro-Québec will take on the responsibility of planning, developing and operating large-scale wind power projects. Large-scale wind power projects are projects which could exceed 1,000 MW of installed capacity. This new role marks a significant shift in Hydro-Québec's strategy and operations. It will require Hydro-Québec to identify strategic zones for wind power projects, integrate transmission requirements, and ensure predictability in labour and equipment procurement, which has not previously been a part of Hydro-Québec's business model. The intention is that an emphasis on large-scale projects will help achieve economies of scale, reduce costs and keep electricity rates competitive. Once the identification of zones for development has been completed and the community partnerships have been formed for large-scale projects, industry partners will most likely be called upon by the project partners to become involved in the development, construction and operation of the wind farm projects.

Medium-scale projects, which are comparable to the projects developed over the past 20 years with installed capacities of up to 350 MW, will still play a role in Hydro-Québec's wind power development strategy. Projects of this size will likely still be required to respond to varying regional realities while providing flexibility to the mix of overall energy sources and capacity. Private developers would still participate in these projects, and Hydro-Québec stated in its Wind power development strategy that it intends on maintaining the current approach of issuing call for tenders for those smaller-scale projects.[1]

As Hydro-Québec begins to promote its new integrated and collaborative approach, this strategic shift is poised to shape the future of wind power development in Québec. The involvement of municipalities and First Nations as financial stakeholders will help foster a sense of ownership and support for these projects with a view to enhancing social acceptability. By addressing challenges such as access to labour and equipment, and coordinating with the transmission system, Hydro-Québec's objective is to ensure that the Province can meet its growing electricity

1 Hydro-Québec, *Charting the Course toward Collective Success: Wind Power Development Strategy*, 2024, p. 8.



demands while advancing its decarbonization goals. This comprehensive strategy will most probably represent a significant opportunity for many players in the wind energy industry.

Upcoming Large-Scale Projects

Since the presentation of its wind power development strategy, Hydro-Québec has made public its plans for two large-scale projects. On July 3, 2024, it was **announced** that the Pekuakamiulnuatsh First Nation, the Atikamekw of Wemotaci, the Domaine-du-Roy MRC and Hydro-Québec would form a partnership for the development of wind power in the Chamouchouane zone west of Saguenay–Lac-Saint-Jean. This zone could accommodate up to 3,000 MW of wind power capacity, which would make such a project one of the largest in North America and represent an investment of approximately C$9 billion.

Then, on October 16, 2024, it was **announced** that Alliance de l'Énergie de l'Est – a coalition of 209 municipalities in eastern Québec and the Magdalen Islands and the Wolastoquiyik Wahsipekuk First Nation – and Hydro-Québec would form a partnership for the development of the Wocawson zone. Located in the southwest portion of the Bas-Saint-Laurent region, this zone could accommodate around 1,000 MW of wind power capacity. Participation in the Chamouchouane and the Wocawson projects would both be divided equally between the community partners and Hydro-Québec.

The three Des Neiges wind projects, located on the Seigneurie de Beaupré territory in the Québec national capital region and which were **announced** in 2022, also fall into the category of large-scale projects. The result of a partnership between Hydro-Québec and private developers Énergir and Boralex Inc., the three wind projects will total 1,200 MW of installed capacity On November 27, 2024, it was **announced** that the Government of Québec had officially authorized via decree the development of the Des Neiges – South sector project, which is the first of the three Des Neiges projects slated to come online.

Lastly, the Government of Québec revealed on December 11, 2024 through its legislative publication the *Gazette Officielle* plans for another large scale wind project on the northern side of the Saguenay River. Situated in the Nutinamu-Chauvin Zone, the project will be developed with the Essipit Innu community and the MRC du Fjord-du-Saguenay as partners. Further details, such as the total capacity of the project, have yet to be announced at press time.

NEW AGREEMENT IN PRINCIPLE FOR CHURCHILL FALLS

On December 12, 2024, the governments of Newfoundland and Labrador and Québec announced the entering into of a major and historic agreement in principle for the purchase of the electricity from and the refurbishment of the Churchill Falls hydroelectric facility, as well as the development of new hydroelectric capacity in the region. For more details, please see our article further below in the **Atlantic Canada Regional Overview chapter**.

ATLANTIC CANADA REGIONAL OVERVIEW

By Elena Drouin, Stephen Furlan, Lynn Parsons, Jacob Stone, Gaetan Thomas, and Gwenyth Wren

Atlantic Canada Regional Overview

Following the last years of continued growth in the power sector and ambitious plans, Atlantic Canada's trajectory in 2024 was marked by consolidation of existing projects and plans with legislative reforms to pave the way for new renewable energy sources. There continue to be opportunities for public and private projects aimed at increasing the supply of energy in the region's provinces (Nova Scotia, Newfoundland and Labrador, New Brunswick and Prince Edward Island), but activities in respect of novel forms of renewables, such as nuclear and tidal, have temporarily cooled.

NOVA SCOTIA

Throughout 2024, Nova Scotia continued its multiple reforms and opportunities for renewables, and the incumbent government's re-election in November 2024 meant planned energy reforms and current policies would continue.

Nova Scotia's Regulatory Restructuring

Highlights for 2024 in Nova Scotia included numerous expansive legislative and regulatory reforms and changes for the energy sector. Following the release on **February 23, 2024** of the recommendations of the **Clean Electricity Solutions Task Force report**, the Nova Scotia legislature enacted Bill 404, **The Energy Reform (2024) Act** (the "Act") in April 2024. This Act substantially overhauled the structure of the province's electricity system and regulations.[1]

Strategic Modernization of Regulatory Oversight

A central feature of the Act is its restructuring of regulatory oversight. Starting as of April 1, 2025, the Nova Scotia Regulatory and Appeals Board ("Regulatory and Appeals Board") and the Nova Scotia Energy Board ("Energy Board") will replace the Nova Scotia Utility and Review Board. These two new boards reflect a more specialized approach to energy regulation, with their roles divided as follows:

— The new Energy Board will be responsible for regulating public utilities in the energy sector, to drive the transition towards a greener grid, by considering the *Environmental Goals and Climate Change Reduction Act* in its decisions.

— The remaining responsibilities of the Utility and Review Board, such as energy rate and tolls fixing, will be assigned to the Regulatory and Appeals Board.

Following the Ontario energy regulatory model, Nova Scotia will introduce in 2025 an Independent Energy System Operator ("NSIESO") to manage the province's electricity system operations. The NSIESO will be an independent non-profit responsible for maintenance of standards for grid interconnections (including open and non-discriminatory access to wholesale and market

1 Changes include an amendment to the ***Electricity Act***, SNS 2004, c 25, the repeal of the ***Utility and Review Board Act***, SNS 1992, c 11 and the introduction of the ***Energy and Regulatory Boards Act***, 2024 c. 2, Sch. A (*An Act to Establish the Nova Scotia Energy Board, the Nova Scotia Regulatory and Appeals Board and the Energy and Regulatory Boards Tribunal*), which is expected to be in effect as of April 1, 2025, and the ***More Access to Energy Act***, 2024 c. 2, Sch. B (*An Act Respecting an Independent Energy System Operator*), where parts have been enacted as of October 24, 2024, and others are expected to be in effect as of April 1, 2025.

participants), and the development of tariffs and standards, effectively replacing Nova Scotia Power Incorporated's transmission branch. Going forward, requests to connect projects to the Nova Scotia grid and the awarding of the purchase power agreements ("PPAs") will be filed with the NSIESO, which has been given a broad mandate to oversee planning and procurement of new energy sources.

Despite the responsibilities granted to NSIESO, the Nova Scotia Energy Minister has retained several discretionary powers, including the power to order a public utility to enter into an agreement for the purchase of services provided by an energy-storage project. In addition, entities regulated as public utilities, such as NS Power, may now apply for Government authorization to enter into ownership arrangements with third parties for projects that support environmental goals and are not under procurement by NSIESO. Previously, the law did not allow a clear path forward for these forms of joint venture. These ownership arrangements will be deemed to be public utilities, and therefore subject to statutory powers and oversight by the Energy Board.

Procurement Changes

The province has moved to improve the structure of energy procurement to create a more competitive, innovation-driven energy production system. Existing rules surrounding procurement of power-purchase agreements were enhanced to integrate varieties of new sources such as energy storage. Furthermore, the prohibition against the construction of nuclear plants by Nova Scotia Power was lifted, opening the possibility of adding nuclear energy generated by small modular plants to the province's energy mix.

Other changes introduced by the Act include increased consumer protection measures and greater consumer representation in regulatory proceedings, as well as additional flexibility and novel targets in rate setting.

New Green Choice Program RFP

As discussed in last year's publication, Nova Scotia announced in December 2023 a 350-MW renewable energy request for proposal ("RFP") entitled the **Green Choice Program** ("GCP"). Under the GCP, customers would be guaranteed to receive up to 100% of their electricity from renewable sources, and benefits of the associated renewable energy certificates derived from such sources. The procurement was limited to wind and solar projects which could commence deliveries not later than in 2027. The RFP's timeline has been revised several times to account for shifts in the RFP process. Based on the **most recent update released in early November**, successful projects were to have been announced by November 28, 2024, and PPAs would have be signed by January 2025, but as of press time only the list of successful projects has been published **here**.

Other New and Ongoing Renewable Projects

In a significant boost to Nova Scotia's green energy infrastructure, the federal government **pledged** throughout 2024 over $100 million for advanced energy projects. Part of the funds were allocated to Nova Scotia Power Inc. for **installing three battery energy storage systems**, located in Bridgewater, Spider Lake, and White Rock, which will provide a combined 50-megawatt ("MW") capacity and 200-megawatt- hour ("MWh") storage capability. Other funds were allocated to critical grid modernization upgrades needed to enhance the province's renewable energy resilience and reliability.

Additional federal funds for renewable energy projects

came in the form of **support of the Canada Infrastructure Bank** ("CIB") and the federal Ministry of Energy and Natural Resources for wind energy projects that prominently featured Indigenous partnerships, most **notably $25 million in funding** for each of the following three projects:

— The *Benjamin Mill Wind Limited Partnership* is a collaborative effort involving Natural Forces Developments and the Wskijnu'k Mtmo'taqnuow Agency ("WMA"), which represent 13 Mi'kmaq bands of Nova Scotia, to develop a 33.6-MW wind energy project located near Windsor.

— The *Higgins Mountain Wind Farm Limited Partnership* and the *Wedgeport Wind Farm Limited Partnership*, two joint ventures between Elemental Energy Renewables Inc., Sipekne'katik First Nation and Stevens Wind for respectively (i) a 100-MW wind energy project located in Wentworth, Cumberland and Colchester Counties, and (ii) an 84-MW wind energy project located in the District of Argyle.

NEW BRUNSWICK

Elections and Legislative Updates

Ongoing energy rate increases throughout 2024 have brought to light concerns in New Brunswick about potential impacts on industrial activity and economic competitiveness. As a result, New Brunswick's approach to energy regulation and legislation remained largely focused, throughout 2024, on consumer pricing and policies, with few changes specifically aimed at accelerating or facilitating new project developments. One exception was the ***Act to Amend the Electricity Act***, enacted on June 7, 2024, which expanded and added flexibility to New Brunswick Power Corporation's ("NB Power's") financing means, in order for it to access alternative funding sources beyond traditional government allocations and conventional bank lending.

Elections resulted in the New Brunswick Liberal Party taking power as of November 2, 2024 under new Premier Susan Holt. Premier Holt has **stated** that she has no intentions to continue plans to invest in shale gas, favouring instead support for development of clean energy in partnerships with First Nations. The party's platform **included** the promise to deliver "an energy plan that provides affordable, reliable, clean energy for New Brunswickers," but it is unclear if this promise means that a new plan will replace the previous government's December 2023 **electricity strategy**, if that strategy will be amended, or if it will remain unchanged.

Charging Up on Battery Storage and Renewables

The December 2023 announcement of the New Brunswick government's **electricity strategy** signalled its intention of procuring a total of 2,000 MW of renewable energy (1,400 MW of wind power, 200 MW of solar and 100 MW of energy storage), but procurement is only scheduled to start in 2027. In the interim, New Brunswick's private sector took steps towards increasing the share of renewable energy generation in the province through wind and storage projects.

- Neqotkuk (Tobique First Nation), Saint John Energy, and Natural Forces **inaugurated in April** the start of production at the 10-turbine and 42-MW Burchill Wind Project in Saint John, which will include New Brunswick's largest battery energy storage system ("BESS") **to date**.

- J.D. Irving Ltd.'s announced in spring of 2024 a $550-million investment to develop the **Brighton Mountain** wind farm, its first foray in the wind energy sector. While the company plans to sell its power to NB Power, under the **Large Industrial Renewable Energy Purchase Program** ("LIREPP"), a PPA **was yet to be signed as of the announcement**. Subject to regulatory approval and pending completion of its **environmental impact assessment**, the 58-turbine project to be located near the hamlet of Juniper in Carleton County would become the largest in the province. Phase 1 of the project, which contemplated 34 turbines for a total capacity of 200 MW, is scheduled to break ground in 2025 and be completed in 2027.

- Irving Pulp & Paper, Limited also **made public** plans for a C$1.1-billion upgrade to its Saint John's westside pulp mill. Upon completion, the mill would include a new biomass plant fuelled by wood by-product, making the plant self-sufficient and able to generate surplus energy to be made available for sale to NB Power. Both projects are intended to **reduce by 18%** the amount of fossil fuel used by NB Power.

New Brunswick has made the expansion of nuclear energy a central part of its decarbonization strategy, setting **a goal in its energy plan** to add 600 MWs of small modular reactor ("SMR") energy production to the grid by 2035.

Year-End Announcements

In an announcement on December 5, 2024, NB Power **confirmed plans for procuring power** from a proposed natural-gas plant which would be built by an unnamed private developer outside Moncton, in a move to reduce the power generated at its Coleson Cove oil-powered generating station. It is expected that the plant will be convertible to use hydrogen and non-emitting energy sources.

Moving into 2025, further developments in renewables are expected to be announced, following the **December 8 announcement** by the Federal government that it would provide over $1 billion to support new energy projects, including for the following initiatives:

- Funding to cover 670 MW of Indigenous-led wind projects, notably through the CIB's Clean Power priority sector and Indigenous Equity Initiative, and other programs;

- $25 million for the 25-MW Neweg Energy wind project partnership between NB Power and the New Brunswick Mi'kmaq First Nations;

- Federal support towards conversion of the coal fired Belledune Generating Station to biomass;

- Additional funding for SMR nuclear energy projects; and

- Funding to cover predevelopment work on the modified Atlantic Loop transmission line which will connect New Brunswick and Nova Scotia.

NEWFOUNDLAND AND LABRADOR

Ongoing Infrastructure Development

Newfoundland and Labrador Hydro **announced** in June that it was planning to invest more than $1 billion to add an eighth unit at the Bay d'Espoir hydroelectric dam on Newfoundland's south coast and a new 150-MW combustion turbine – with the aim of improving the energy grid. The six-year project's price is an estimated $516 million. According to Newfoundland and Labrador Hydro's projections, electricity demand may exceed supply as early as 2030. This presents a significant concern for the Public Utilities Board, which has underlined the need to strengthen the province's grid.

Churchill Falls

In a surprise development, Hydro-Québec and Newfoundland and Labrador **signed in December** a memorandum of understanding ("MOU") for the Churchill Falls hydroelectric project, ending their existing 65-year contract. Under the terms of the new MOU, the current rate paid by Hydro-Québec for energy supplied by Churchill Falls will increase to 5.9 cents per kilowatt hour ("kWh"), from the current price of 0.2 cents/kWh. New price escalation mechanisms could result in estimated annual revenues for energy sales of around $1 billion from 2024 to 2040, and $2 billion as of 2041, with further escalations starting in 2056

In addition to renegotiating the terms and pricing of the 7,200 MW of energy to be supplied to Hydro-Québec, the agreement contemplates (i) the development of the long-discussed Gull Island project through a joint venture between Hydro Québec and Newfoundland and Labrador

Hydro, the phase 1 of which could generate 2,250 MW, and (ii) an expansion of the Churchill Falls facility.

— The Gull Island Project would be led by Hydro-Québec as project lead and construction manager responsible for the risks, and it would later be operated by Newfoundland and Labrador Hydro. The project would be jointly owned by Newfoundland and Labrador Hydro (60%) and Hydro-Québec (40%). A total of 225 MW of its production would be reserved for Newfoundland and Labrador's internal consumption and needs, with the balance being exported to Québec. The target date for the Gull Island Project's commissioning is 2035.

— The Churchill Falls facility expansion contemplates construction of a new underground powerhouse near the existing reservoir, for a generation capacity increase of 550 MW. The expansion would be developed and operated by the Churchill Falls (Labrador) Corporation, which is owned and controlled by Newfoundland and Labrador Hydro (65.8%) and Hydro-Québec (34.2%).

The MOU is supported by the Innu Nation, which have been granted employment priority for construction jobs on the new projects. The MOU is expected to be formalized by 2026.

March Towards Green Hydrogen

Building on the **2022** and 2023 talks and agreements between Canada and Germany, the two countries committed $600 million in **July** to launch a hydrogen export initiative in Atlantic Canada, marking a significant step in developing a clean energy supply corridor. The investment, with each country contributing $300 million, aims to support projects to transform wind energy into green hydrogen for export to Germany. In **April**, one of the four wind-to-hydrogen proposals publicly developed in the province and led by World Energy GH2 reached a key milestone when it obtained a provincial environmental approval. Located on Newfoundland's west coast, the Nujio'qonik project involves installing over 300 wind turbines across the Port au Port Peninsula and Codroy Valley and includes plans for a hydrogen-ammonia plant in Stephenville.

PRINCE EDWARD ISLAND

Guarding the Grid from Climate Change Impacts

PEI's main utility, Maritime Electric, released a 75-page **Climate Change Adaptation Strategy**, in March that it claims will help protect PEI's electrical grid against future climate change impacts. Maritime Electric is constructing a switch station in western PEI which will create a transmission loop to provide an alternate route to serve its customers in the event of an outage to one of the transmission lines. The project is expected to be completed in 2025. Most concepts presented in the Maritime Electric strategy focus on enhancing the grid's existing infrastructure with advanced technologies designed to prevent cascading power outages, and ice accumulation. Additionally, substations will be retrofitted to improve their resilience against high-wind conditions.

Over-Electrification

In October 2024 the CEO of Maritime Electric raised the alarm telling the **standing committee on Education and Economic Growth of the Legislative Assembly** that energy demand is **outpacing its ability to provide energy**. PEI currently purchases energy from off-Island sources; however, increased consumption in nearby Atlantic provinces, as well as planned power plant closures in Nova Scotia and New Brunswick, mean that neighboring provinces have less energy available to supply.

Solar Growth

At the beginning of 2024, **two large-scale solar farms, Summerside's Sunbank and the Slemon Park Microgrid**, became fully operational. This development has significantly increased PEI's solar energy production, more than doubling its capacity. Both facilities commenced operations concurrently at the start of the year. Consequently, monthly solar energy production, which previously relied heavily on residential rooftop installations, surged from approximately 1,475 MWh per month in 2023 to over 6,000 MWh by April.

OFFSHORE WIND

At a regional level, highlights of 2024 included the continued progress towards making offshore wind projects a reality, through concerted legislative and policy activities and reforms at the federal and provincial levels. Most notably, royal assent was given on October 3, 2024 to 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"), more than a year from when it was first tabled before the House of Commons. This legislation creates a framework for the development and regulation of offshore renewable energy projects in both Nova Scotia and Newfoundland and Labrador. It also amends existing regulation of offshore petroleum activities, aligning them with new provisions.

As Bill C-49 amended the ***Canada–Newfoundland and Labrador Atlantic Accord Implementation Act and the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*** (the "Atlantic Accords Acts"), regulation of current petroleum projects has been expanded and jurisdictional rules regarding domestic and internal sea boundaries have been clarified.

New Regulatory Framework

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

Regulatory authority for offshore wind power will be exercised by two existing and jointly managed offshore boards, which already regulate oil and gas projects: the Canada-Nova Scotia Offshore Energy Regulator (previously the **Canada-Nova Scotia Offshore Petroleum Board)** and the Canada-Newfoundland and Labrador Offshore Energy Regulator (previously the **Canada-Newfoundland and Labrador Offshore Petroleum Board)**, (the "Boards").

Regulation of renewables, by the Board will cover safety, environmental protection, decommissioning, and royalties, with procedures ranging from environmental assessments, public hearings, and dispute resolution processes related to offshore renewable energy projects. However, while exploration, development, and production of offshore renewable energy resources, such as wind, tidal or wave energy, will be authorized by way of an application to the Boards, the decision to issue calls for bids will be subject to the approvals of both the federal and provincial ministers. Our readers interested in the details of Bill C-49 are invited to read our **previous article on this topic**.

Next Steps

Both Nova Scotia and Newfoundland and Labrador have or will pass mirror legislation to complete the framework initiated by Bill C-49.

Both provinces are also expected to launch, or have launched bids, for offshore wind projects. Nova Scotia has set a target to issue **five gigawatts of licences for offshore wind by 2030** under the *Marine Renewable-energy Act*, with a **stated aim** to encourage green hydrogen production. Leasing under this scheme would be expected to commence as of 2025.

ENVIRONMENTAL LAW

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Environmental Law

KEY DEVELOPMENTS IN 2024

In 2024, there were a number of key environmental law developments across Canada with potential impacts on the power sector. Highlights include the following:

British Columbia

- **B.C. Establishes New Ministries to Address Mining and Energy Industries.** Following the B.C. provincial election, the NDP government divided the Ministry of Energy, Mines and Low Carbon Innovation to form the new **Ministry of Mining and Critical Minerals** and the **Ministry of Energy and Climate Solutions**. The provincial government **has stated** that this change reflects "the government's commitment to leverage B.C.'s strength as a clean-energy powerhouse with the critical minerals that are essential to growing the clean economy" and provided that the Ministries will have the following responsibilities:
  - **Energy and Climate Solutions:**
    - oversee B.C.'s electricity, alternative energy and petroleum resource sectors;
    - increase and expand electricity and low-carbon energy projects in the province;
    - ensure energy policies align with climate goals; and
    - oversee the North Coast Transmission Line and BC Hydro's Capital Plan.
  - **Critical Minerals:**
    - advance the provincial strategy for mining and critical mineral projects;
    - provide oversight and support for 17 new critical minerals projects working toward starting construction; and
    - oversee the ongoing *Mineral Tenure Act* reform and other regulatory processes and timelines.
- **Significant Investments in Clean Energy and Climate Preparedness Initiatives.** For example, in January 2024, the Province announced BC Hydro's **updated 10-year capital plan**, which includes $36 billion in regional and community infrastructure investments in B.C. Further, on September 6, 2024, the provincial government **announced** that it had invested $89 million in clean economy infrastructure across the Province, including in respect of providing energy-efficient buildings, clean energy and clean transportation options. On September 18, 2024, B.C. **announced** that it was providing 65 communities with funding for projects relating to climate adaptation through the through the Disaster Risk Reduction – Climate Adaptation

stream of the fund. Significant funding continues to be provided through the **CleanBC Industry Fund** to support industry in reducing emissions.

— **Creation of Electric Highway.** During 2024, B.C. was working to complete its **electric highway**, being a comprehensive network of public electric vehicle ("EV") fast-charging stations along all highways and major roadways. The intention is to allow British Columbians to drive throughout the entire Province utilizing EVs.

— **Cryptocurrency Regulations.** The ***Energy Statutes Amendment Act, 2024*** received royal assent on May 16, 2024, amending the *Utilities Commission Act* to provide the Lieutenant Governor in Council with the ability to make regulations in respect the provision of service from a public utility for the purpose of cryptocurrency mining. In June, the ***Cryptocurrency Power Regulation*** was introduced, extending the temporary prohibition on supplying service to new cryptocurrency projects until December 2025 in order to provide the government with time to develop a regulatory framework for future cryptocurrency mining operations.

— **Exemptions for Hydrogen Energy Services Providers.** In April 2024, the B.C. government approved the British Columbia Utilities Commission's ("BCUC") recommendations in its Hydrogen Energy Services Inquiry Final Report, which found that regulation of the hydrogen energy service market in B.C. could hinder development of a competitive market. Accordingly, in May 2024, the BCUC issued three orders to exempt three classes of hydrogen energy services from active BCUC regulation under the *Utilities Commission Act*: **hydrogen as a transportation fuel**, the **production of hydrogen as a fuel for the production of electricity, or as a fuel for transportation or heating**, and **hydrogen delivery by truck.**

— **Introduction of Administrative Penalties Framework under *Water Sustainability Act*, *Ecological Reserve Act* and *Park Act*.** On January 12, 2024, the ***Administrative Penalties (Water Sustainability Act) Regulation*** was made through order-in-council, specifying penalties which may apply to contraventions under the *Water Sustainability Act* and its regulations. On May 3, 2024, the ***Administrative Penalties (Ecological Reserve Act) Regulation*** and ***Administrative Penalties (Park Act) Regulation*** were each made through order-in-council, specifying the process for imposing, contesting and enforcing administrative penalties for contraventions of the *Ecological Reserve Act* and *Park Act*, along with their respective regulations. The enactment of various administrative penalty regulations may foreshadow more enforcements efforts under these regulatory regimes.

— **Updates to Greenhouse Gas ("GHG") Regime for Industrial Emitters.** Industry sector emissions in B.C. are governed by the ***Greenhouse Gas Industrial Reporting and Control Act*** ("GGIRCA"). GGIRCA also governs carbon credit trading activities in the province. In 2024, the GGIRCA regime continued to evolve. On February 16, 2024, the ***BC Carbon Registry Regulation*** (the "Regulation") was made. The BC Carbon Registry (which enables the issuance, transfer and retirement of compliance units) is continued under this Regulation, which sets out, among other things, who may utilize the registry, the processes to apply for an account, and rules applicable to compliance unit transactions. In spring of 2024, the Province transitioned to an output-based pricing system

("**OBPS**") for industry from the prior carbon tax model. For further details on the OBPS, please refer to the "**Update on CleanBC Roadmap to 2030**."

— **Introduction of Emergency Management Planning by Lead Ministers.** On July 6, 2024, **amendments** to the *Emergency and Disaster Management Regulation* were introduced which require various ministers to prepare and maintain risk assessments and emergency management plans in respect of specified hazards. Specified hazards include explosions and emissions (including gas explosions or leaks related to pipelines, gas wells, refineries or power generation facilities), power outages (including electrical power outages and overloads) and hydrologic hazards (including dam incidents and failure, drought and water scarcity).

— **Creation of Environmental Assessment Dispute Resolution Facilitator Regulation.** On July 9, 2024, **regulations** under section 5 of the *Environmental Assessment Act* were introduced to provide additional details on the dispute resolution facilitators process following a referral by a participating Indigenous Nation or the chief executive assessment officer in respect of a project seeking an environmental assessment certificate.

— **Requirements for Off-Site Mitigation Activities Brought into Force.** On July 22, 2024, select provisions of the ***Oil and Gas Activities Amendment Act, 2018*** were brought into force, including the requirement for the commission to set out in permits for specified classes of oil and gas activities the off-site environmental mitigation activities that will be carried out by the permit holder, and the provisions which allow the Lieutenant Governor in Council to enact regulations regarding off-site environmental mitigation activities.

— **B.C. Court Sheds Light on Content of Secondary Liability under Environmental Statutes.** In *R v. Mossman*, **2024 BCSC 443**, the Supreme Court of British Columbia held that liability under Section 121 of the ***Environmental Management Act***, which provides that "if a corporation commits an offence under this Act, an employee, officer, director or agent of the corporation who authorized, permitted or acquiesced in the offence commits the offence whether or not the corporation is convicted" does not require a proof of intention *mens rea*) to have allowed the company to commit the offence or any proof of knowledge that the company was committing the offence. This decision in effect ensures that the strict liability nature of offences under public welfare statutes extends to the secondary liability provisions governing the liability of employees, directors, officers, and agents of corporations that commit offences, leaving due diligence as the primary defence where the corporation has committed an offence.

Alberta

— ***Electric Energy Land Use and Visual Assessment Regulation*:** On December 6, 2024, the Government

of Alberta ("Alberta") enacted the ***Electric Energy Land Use and Visual Assessment Regulation*** (the "*Land Use and Visual Assessment Regulation*") as new regulations under the ***Alberta Utilities Commission Act***. These new regulations create new requirements for applications to the Alberta Utilities Commission ("**AUC**") for power plants. The changes follow the release of the AUC's "**Module A Report**," which presented a summary of submissions and observations collected by the AUC related to development on specific types or classes of agricultural land, the impact of power plants on viewscapes, reclamation security requirements, development on Crown lands and the role of municipal governments in the development and review of power plant applications.

— Subject to certain exceptions, the *Land Use and Visual Assessment Regulation* applies to new applications for the construction and operation of power plants under AUC **Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines*** ("AUC Rule 007"). These regulations do not apply to:

  — the construction or operation of (i) small power plants (i.e., less than 1 megawatt ("MW"), (ii) isolated generating units, and (iii) micro-generation generating units;

  — the construction or operation of a power plant situated on a reserve; and

  — minor amendments to existing power plant approvals that do not:

    — directly and adversely affect any person,

    — have any adverse environmental impact,

    — result in non-compliance with AUC Rule 012, and

    — a change to the terms or conditions of any existing approval, permit or licence.

While these new requirements do not apply to already approved power plants, the *Land Use and Visual Assessment Regulation* will apply to any applications to the AUC for amendments to existing power plant approvals which require more significant amendment including amendments to the terms and conditions contained within the original AUC approval and those which requiring additional assessment to consider the impacts to stakeholder, environmental matters and noise.

At a high level, the *Land Use and Visual Assessment Regulation* target three areas:

Agricultural Land

— All new applications for wind and solar power plants on high-quality agricultural land as defined in the regulation must include an agricultural impact assessment in accordance with Section 4 of the regulation. Section 5 of the regulation requires the owners of wind and solar power plants on high-quality agricultural land to report to the AUC on agricultural productivity within 36 months from the start of operations. According to **AUC Bulletin 2024-25**, *Changes to interim information requirements for power plant application*, the AUC intends to work with stakeholders to develop these reporting requirements for inclusion in **AUC Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants***.

For now, the AUC will solicit information from applicants in the form of an interim information requirement on how they will evaluate and improve the performance of any co-location agricultural proposal. The requirement can be found in the agricultural land section of the appendix of AUC Bulletin 2024-25.

Irrigability Assessment

All proposed power plant types within the "**White Area**" (identified within the map annexed to Ministerial Order M.O. 71/85 dated May 7, 1975) must identify whether (i) the project lands contain irrigation infrastructure; (ii) the project lands are within an irrigation district and if so whether, (a) the project has been discussed with the irrigation district; (b) the irrigation acres (either permanent, terminable or annual) are or have been assigned to the project lands; (c) an application for water rights or irrigation acres has been made for the project lands; and (iii) the landowners have obtained a Private Irrigation Water Licence for irrigating the Project lands. The AUC stated that it will use this information to determine on a case-by-case basis whether more detailed irrigability assessments will be required for a project.[1]

1 AUC **Bulletin 2024-25** (18 December 2024) at 2.

Visual Impact Assessments

- All new applications for all types of power plants within **buffer zones and visual impact assessment** zones (defined in Schedule 2 and Schedule 3 to the regulation) must submit a visual impact assessment. AUC Bulletin 2024-24 ("**Appendix A**") contains interim information requirements for what a visual impact assessment should contain.

- ***Conservation and Reclamation Amendment Regulation*:** On December 6, 2024, Alberta also enacted the *Conservation and Reclamation Amendment Regulation* by **Order in Council 269/2024** under the *Environmental Protection and Enhancement Act* ("**EPEA**"). This regulation introduces updates to the existing regulatory framework, affecting the operations of wind and solar power plants, including:

  - a new *Code of Practice for Solar and Wind Renewable Energy Operations* ("Code"). Those carrying on the construction, operation or *reclamation* of wind and solar generation projects will be required to comply with the Code.

  - imposing security obligations for end-of-life reclamation. An operator of a wind or solar project will be required to provide security for its end-of-life reclamation obligations.

  An operator that applies for registration for a Specified Activity generating electricity from wind power or solar power, and provides security to a registered owner of the land under a surface lease, is exempt from the requirement to provide security.

- **Bill 21, *Emergency Statutes Amendment Act*:** On May 9, 2024, Alberta tabled Bill 21, ***Emergency Statutes Amendment Act, 2024*** to amend a number of statutes key to responding to emergencies including wildfire, flood and drought. Specifically, Bill 21 will amend the ***Emergency Management Act***, the ***Forest and Prairie Protection Act***, the ***Water Act*** and the ***Election Act*** to grant the provincial government greater scope of authority to respond to emergencies including wildfire, flood and drought.

- **Alberta Drought Response Plan:** On August 14, 2024, Alberta released its **Alberta Drought Response Plan**. The intent of the Drought Response Plan is to ensure Alberta is prepared for the potential of widespread drought. The plan describes preparation, planning and response activities that Alberta Environment and Protected Areas ("**EPA**") will implement to effectively address the full range of possible drought conditions, which may range from localized impacts to multiple river basins simultaneously.

  The Drought Response Plan will be led by EPA and necessitates actions by Alberta Agriculture and Irrigation, Alberta Municipal Affairs, Alberta Forestry and Parks, the Alberta Energy Regulator, and other affiliated ministries. The plan itself is structured around five management stages. Currently, Alberta is situated at stage 4, with the emergent possibility of escalating to stage 5. This fifth stage is characterized as an emergency situation where conventional management strategies may prove inadequate for ensuring access to drinking water, protecting public safety, critical infrastructure, livestock welfare, or vital environmental needs.

  Should a water emergency be declared, the plan permits the issuance of water management orders that could result in the suspension of certain authorizations under the *Water Act*, halting water diversion, and strictly regulating the use and allocation of water. These orders, as specified in sections 99 and 107 of the *Water Act*, may also direct necessary actions to counteract or mitigate detrimental effects on aquatic ecosystems or human health.

  Additionally, the plan encompasses a range of regulatory and non-regulatory tools to address drought conditions across all stages. Non-regulatory options include advocating for voluntary water conservation and the formation of water-sharing agreements. Regulatory mechanisms comprise the approval of water shortage response plans, issuance of temporary diversion licenses, facilitation of temporary water licence transfers, arrangements for water assignment, and modifications to existing licenses and approvals under the *Water Act*. Other available mechanisms include water management orders can be enacted under the *Water Act,* alongside environmental and emergency environmental protection orders under the *Environmental Protection and Enhancement Act*.

- **Alberta Coal Industry Modernization Initiative:** On December 20, 2024, Alberta announced the Alberta Coal Industry Modernization Initiative ("**CIMI**"). CIMI addresses the **2021 Coal Policy Committee**'s recommendations to build a long-term legislative and regulatory framework to guide responsible coal development across the province. It builds on the **1976 Coal Development Policy** that was designed to protect Alberta's foothills (Eastern Slopes) while encouraging responsible mineral development. Highlights of the new policy include:

- The protections set out in law and in the **1976 Coal Development Policy** for National Parks, provincial Parks, wildland parks, wilderness areas, ecological reserves and provincial recreation areas will continue.
- All new mining proposals must use techniques which use best water practices and prevent adding selenium into waterways, anywhere in Alberta. New proposals will either need to be underground mines or use mining technologies (such as highwall automated underground mining) that move minimal amounts of overburden, to prevent selenium leaching and siltation. New proposals will either need to be underground mines or use mining technologies such as highwall automated underground mining, which move minimal amounts of overburden, to prevent selenium and silt entering our water.
- Mountaintop removal coal mining has not occurred in Alberta, but it will now be specifically prohibited.
- There will be no new open-pit coal mines approved for the Eastern Slopes region.

Ontario

- **New Regulations for Carbon Storage in Ontario:** On January 1, 2024, ***new regulations*** came into effect under Ontario's ***Oil, Gas and Salt Resources Act***, enabling the authorization of carbon storage demonstration projects using private wells. The regulation allows businesses to evaluate new technologies for carbon storage, requiring a designation from the Minister of Natural Resources and Forestry. Designated projects must secure all necessary permits and licenses, comply with the operating standards of the ***Provincial Standards for Oil, Gas and Salt Resources***, and maintain financial security through an irrevocable letter of credit. The regulation is a step toward broader implementation of carbon storage in Ontario, supporting the province's goals for reducing greenhouse gas emissions and transitioning to a low-carbon economy.
- **Ontario's Clean Energy Opportunity:** Early in 2024, the Ontario Ministry of Energy and Electrification released its **Report of the electrification and energy transition panel**. The report contains broad recommendations on opportunities for the energy sector to help Ontario's economy prosper and prepare for electrification and the energy transition, and to identify opportunities to support emerging electricity and fuel planning needs. A dominant theme throughout the report and recommendations is the need for greater Indigenous inclusion, economic reconciliation, and participation and partnership in the clean energy

economy. The report also calls for establishment of an Integrated Long-Term Energy Plan, prepared by the Ministry of Energy and Electrification and covering the gas and electricity sector. While these are only recommendations, they provide insight into the potential direction for Ontario's energy-related policies.

— **Ontario's Response to Electric Vehicle Growth:** To respond to the growth of EV owners in Ontario, the Ontario Energy Board ("OEB") **initiated measures** to facilitate the integration of EVs into the provincial electricity system. In February 2024, the OEB issued a province-wide streamlined procedure that all local utilities must follow starting on May 27, 2024. The Government of Ontario committed to an investment of $91 million in the **EV ChargeON program**. This initiative aims to establish thousands of new EV charging stations throughout Ontario.

Québec

— **Bill 81, an Act amending various environmental provisions**. In November 2024, ***Bill 81, an Act amending various environmental provisions***, was introduced to the National Assembly of Québec amending many environmental laws affecting various industries. Amendments that may affect, directly or indirectly, the development of energy projects include:

Threatened or Vulnerable Species

Proposed modifications to the *Act respecting threatened or vulnerable species* seems to answer the industry request by introducing an authorization mechanism allowing the Ministry of Environment, Fight against Climate Change, Wildlife and Parks ("**MEFCCWP**") or the government to authorize activities otherwise prohibited when they consider that these activities do not jeopardize the survival of the species. The bill also amends the *Natural Heritage Conservation Act* to grant the government the power to determine by regulation the activities prohibited in a natural area designated by a plan as well as those that could be carried out there without authorization. These modifications, if adopted, should give more flexibility to project implementation in the province.

Environmental Impact Assessment

The government wishes to introduce a new sectoral or regional environmental assessment procedure ("EESR") to assess the development of a particular sector of activity or region. The goal would be to ensure that the development of the territory or sectors of activity respects the government's environmental and social considerations. The EESR would be completed before the Environmental Impact Assessment ("EIA"), so it would be adding to the already stringent process.

The government claims that this new procedure purpose is to ensure that EIAs are more relevant and effective, as they consider the specific environmental, social, and economic contexts of the region or sector of activity before their specific EIA. The terms of application of the EESR and the related deadlines would be specified by government regulation. However, a transitional provision is planned to allow the evaluation of certain plans or programs while awaiting the enactment of this regulation. Each plan or program that would be subject to an EESR before the entry into force of this regulation would be the subject of a specific decree.

Fast Track for Initial Project Phase

In order to ensure progress of Québec's climate change mitigation targets and energy transition goals, Bill 81 aims to provide the Québec government with discretionary authority to fast-track certain initial phases of projects, which are components of broader projects subject to the Québec Environmental Impact Assessment and Review Procedure ("Procedure"). As Bill 81 stands, this would only be possible for projects led by ministries or Hydro-Québec.

The types of preliminary work eligible for this accelerated process would be those not already mandated to undergo the Procedure, thereby excluding, for example, the construction of high-voltage electric transmission lines. To be eligible to the fast track, it would have to be substantiated that the early-phase work, such as building access roads, requires a more rapid execution, while the overarching project, would continue to be evaluated under the standard Procedure. This special measure would only be instituted upon the minister's recommendation, after thorough evaluation of the project and consultation with interested parties. With ministerial authorization, the initial works would commence, while the remainder of the project would continue to be subject to the full scrutiny of the Procedure.

New Regulatory Powers on Residual Materials Reduction

In the context where residual material management is an important environmental issue, Bill 81 amends sections of the ***Environmental Quality Act*** ("EQA") regarding the reduction in the production of residual materials, the recovery and reclamation of residual materials, and the compensation for municipal services. Bill 81 aims to expand the regulatory powers of the Québec government and the minister, notably to regulate (i) the conditions and prohibitions applicable not only to the manufacturing but also to any form of availability of designated containers, packaging, printed matters, or other products, as well as their materials; and (ii) any measures to limit the generation of residual materials (e.g., valorizing unsold new products instead of sending them directly to landfills). As most of the proposed amendments for residual materials reduction affect regulatory powers, new regulations or regulatory amendments following the adoption of Bill 81 will be expected to fully implement the envisioned measures.

Declaration on Certain Thermal Discharges

In September 2024, a draft ***Regulation on the Mandatory Declaration of Certain Thermal Discharges*** was published by the MEFCCWP reportedly to answer to electricity supply issues and to promote further reduction in GHG emissions. It imposes obligations to energy distributors such as HQ and Energir and to companies that are large energy consumers.

Indeed, the draft regulation provides that targeted energy distributors must annually submit to the MELCCWP a statement regarding the energy consumption of individuals who consume an amount of energy equal to or greater than 100,000 gigajoules per year. Also, any person operating an establishment emitting thermal discharge and having consumed an amount of energy equal to or greater than 150,000 gigajoules will have to submit to the minister a declaration containing various information such as the nature of the thermal discharge, its source, temperature, flow and pressure of same using the best available data. The draft regulation provides that thermal discharges from a temporary installation and diffuse thermal discharges not released at an identifiable location are exempted from reporting.

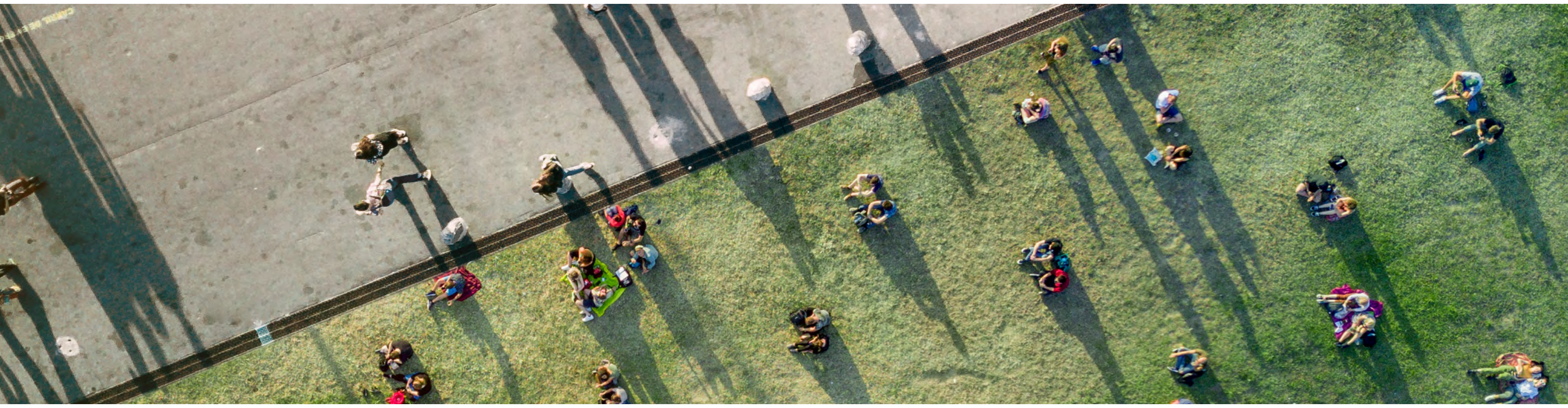
Consultation on Bill 81 is ongoing and as a result the above-mentioned thresholds and targeted thermal discharges may be modified in the next version planned to be published in 2025.

Zero-emission standard for heavy motor vehicles

Bill 81 also proposes amendments to **the Act to increase the number of zero-emission motor vehicles in Québec** (c A-33.02), to enable the government to adopt measures to encourage manufacturers to increase the supply of electric heavy motor vehicles in Québec. The amendments proposed in Bill 81 include the introduction of a credit system linked to the sale and lease of zero-emission heavy motor vehicles. These changes will impact any manufacturer selling or leasing more than 50 heavy motor vehicles and do not apply to buses and minibuses.

Federal

— ***Clean Electricity Regulations.*** On December 18, 2024, the federal government enacted the ***Clean Electricity Regulations*** ("CER"). Beginning in 2035, the CER will set limits on carbon dioxide pollution from almost all electricity generation units that use fossil fuels. This final version of the CER is the result



of nearly three years of feedback from provinces, territories, Indigenous communities and industry. First proposed in August 2023, the CER received pushback from provincial governments and industry over certain aspects, including a prohibition against electricity generation units emitting more than an annual average of 30 tonnes of carbon emissions per gigawatt hour ("GWh") of electricity generated over a calendar year.

In light of the feedback, in February 2024, the federal government released an update to the proposed CER. Key changes incorporated in February included: (i) the blanket 30 t/GWh annual performance standard was replaced with a unit-specific annual emissions limit; (iii) an adjusted underlying performance standard; (iv) incorporating the ability to issue, bank or transfer compliance credits (i.e., pooling); and (v) the ability for operators to use offsets in the event a unit to exceed its annual emissions limits.

The now-finalized CER incorporates additional feedback from provinces and stakeholders, including pushing back the date to fully decarbonize electricity grids from 2035 to 2050. Though signed into law in December 2024, the prescribed limits within the CER come into effect January 1, 2035 and emissions reductions will then be enforced with the goal of reaching net-zero by 2050.

The CER applies to a unit that meets the following criteria:

— the unit uses any amount of fossil fuels to generate electricity;

— the unit has a generation capacity of at least 25 MW; and

— the unit is connected to an electricity system that is subject to the North American Electricity Reliability Corporation's ("NERC") standards.

However, depending on when a unit is commissioned, it may be exempt from certain CER requirements. For example, the emission limit and calculation requirements will not apply to units, other than units that combusts coal, until January 1 of the calendar year following the unit's end of prescribed life, if it:

— has a commissioning date after December 31, 2009, but before January 1, 2025;

— is a "planned unit"; or

— is a "boiler unit" as described in the ***Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*** that has an end of prescribed life after December 31, 2034.

A "planned unit" is a unit with its commissioning date between January 1, 2025, and December 31, 2034, and meets the other specified requirements under Section 3 of the CER, such as having construction start on or before December 31, 2027.

Registration and Reporting Requirements

The owner or person who has charge, management or control of a unit (responsible person) must submit to the Minister of the Environment of Climate Change of Canada (**Minister of Environment**) a registration report for that unit by the later of (1) December 31, 2025, or (2) the 60th day after the day the unit meets the eligibility requirements (i.e., uses fossil fuels, >25 MW capacity, and is connected to a NERC electricity system).

Units must also submit emission reports and reconciliation reports at the beginning of the calendar year that its annual emission limit begins to apply. Units that produce a net annual supply of electricity and that are subject to an annual emission limit must submit their annual emission report by June 1 of the year following a compliance year. The emissions report includes all information relating to the facility's net supply, the unit's total annual emissions in the compliance year and information required for the issuance of its compliance credits (if applicable).

Units are also required to submit an annual reconciliation report by December 15 of the year following the applicable compliance year that includes information on Canadian offset credits being remitted, information on compliance credits that are being remitted or banked, as well as information on any tradeable compliance credits that were transferred or received.

If a unit intends to maintain a net supply of electricity is zero or less (e.g., cogeneration unit), the responsible person for that unit may choose to submit to the Minister of the Environment a declaration of net supply for the unit. The declaration must be submitted within 12 months before the emissions prohibition would apply to the unit. So long as the facility does not have a net supply, the unit is exempt from quantifying its emissions.

Emission Limit Requirement

Beginning in 2035, the CER prohibits a unit's emissions above its annual emission limit, measured in tonnes of CO_2 per year per unit, based on its electricity generating capacity. The emission intensity caps used to calculate a unit's emission limit is 65 t/GWh during the period of 2035 to 2049, and 0 t/GWh in 2050 onwards.

Compliance and Flexibility Mechanisms

Between 2035 and 2049, a unit may emit up the equivalent of 35 t/GWh over the prescribed emission intensity by remitting an equivalent amount of eligible offset credits. Beginning in 2050, a unit may emit up to 42 t/GWh above the prescribed emission intensity by remitting such offsets.

Currently, only offset credits issued under the ***Canadian Greenhouse Gas Offset Credit System Regulations*** and provincial credits recognized under the ***Output-Based Pricing System Regulations*** are considered eligible offset credits. Furthermore, the greenhouse gas reductions must have occurred no more than eight calendar years before the year which the credit is remitted.

The **regulatory impact analysis statement** following the regulations set out that a unit may remit eligible compliance credits equivalent to the amount of CO_2 emissions above its annual emission limit. These credits are remitted through the reconciliation report for the unit with respect to the relevant compliance period. Compliance credits may only be used to comply with a unit's emission limits until December 31, 2049, and may not be used for the 2050 compliance year and going forward.

Certain compliance units are eligible to be issued transferable credits which that unit can either bank for its own use, or transfer to another unit that is eligible to remit transferable credits ("pooling").

In general, and as set out in section 31(1) of the CER, transferable compliance credits that are generated by one unit may be "pooled" with another unit if:

— the unit is subject to an annual emission limit;

— the unit was commissioned before January 1, 2030 (i.e., an existing unit or a new unit commissioned between 2025 and 2030) or is a "planned unit";

— the unit does not combust any amount of coal; and

— the unit does not produce useful thermal energy.

Cogeneration

Cogeneration units are only subject to an annual emission limitation in calendar years where the cogeneration facility produces a net supply of electricity to the grid greater than zero (i.e., their annual supply of electricity to the grid is greater than the annual consumption of electricity from the grid) as calculated under the CER. A cogeneration unit may subtract from its total annual emissions the emissions attributed to the production of useful thermal energy (e.g., steam that is not used to generate electricity).

Furthermore, the finalized CER enables existing cogeneration units to calculate their annual emission limit based on their full electricity generating capacity, but only need to account for the emissions associated with the electricity that is supplied to the grid (measured in terms of net supply, in case their host facility also purchases electricity from the grid) to comply with its emission limit. Emissions associated with electricity consumed on-site do not have to be included for an existing cogeneration unit to comply with its annual emission limit for the 2035 to 2049 compliance years.

Starting in 2050, all emissions from electricity generation for existing cogeneration units are relevant to compliance with their annual emission limits, including electricity that is used behind-the-fence, if such units have a positive net supply. The CER also requires new cogeneration units (i.e., those with commissioning dates on or after January 1, 2025, and which are not "planned units") to account for all emissions from electricity generation, including electricity that is used behind-the-fence, to comply with its annual emission limits starting January 1, 2035.

Emergencies

The CER permits emissions generated during an emergency circumstance to be deducted from a unit's total emissions where the necessary conditions are met. In the event of an emergency circumstance, upon the direction of an electric systems operator, a temporary emissions exemption of up to 30 days can be triggered for the emissions generated by a unit to alleviate the disruption or significant risk of disruption

to electricity supply to a province or in a contiguous province or state.

There are two types of emergency circumstances: an irresistible emergency event, determined by the electricity system operator, which is natural or arises from human action. The irresistible emergency event must be outside the control of the electricity system operator and the responsible person for the unit. The second emergency circumstance is a risk to human health and safety, of any duration, determined by the Minister of the Environment.

Renewable Natural Gas

A unit's total emissions will exclude the emissions associated with the combustion of biomass, including renewable natural gas (RNG), that occurs directly in the unit. A unit's total emissions will also exclude emissions from RNG that has been blended into a North American natural gas pipeline network that is physically connected to the unit, if the volume of RNG utilized is specified in a contractual agreement and the necessary conditions in the CER are met.

Carbon Capture and Storage

A unit's total emissions can exclude the quantity of emissions captured by a carbon capture and storage project that permanently stores such emissions. The geological site into which the CO_2 is injected into must be (1) a deep-saline aquifer into which injection is for the sole purpose of storage; or (2) a depleted oil reservoir into which injection is for the purpose of enhanced oil recovery. Interestingly, the inclusion of a depleted oil reservoir from the CER departs from the Federal Government's previous omission of such reservoirs for carbon capture and storage from eligibility for the equivalent federal income tax credits.

— **Amendments to the *Impact Assessment Act*:** On June 20, 2024, the omnibus federal budget **Bill C-69** received royal assent.[2] As a result, the amendments to the ***Impact Assessment Act*** ("IAA") included in Bill C-69 came into force. The amendments were in response to the Supreme Court of Canada's ("SCC") findings in *Reference re: Impact Assessment Act*.[3] Key amendments to the IAA include:

  — revising the definition of "effects within federal jurisdiction" to focus on "non-negligible adverse change" relating to matters of federal purview;

  — limiting the Minister's ability to designate projects to those which may cause adverse effects within federal jurisdiction or direct or incidental adverse effects;

2 **Bill C-69**, *An Act to implement certain provisions of the budget tabled in Parliament on April 16, 2024,* First Session, 44th Parl, 2024 (assented to 20 June 2024), SC 2024, c 17.

3 *Reference re Impact Assessment Act*, **2023 SCC 23**.

— facilitating the substitution of provincial processes for environmental assessment; and

— focusing the approval decision, in respect of a project, on whether the adverse effects on matters under federal jurisdiction will be significant – and if so, whether such effects will be justified in the public interest.

While the IAA amendments faced notable scrutiny in the Senate's Energy, the Environment and Natural Resources Standing Committee ("**ENEV Committee**") meetings, the amendments received royal assent without any revisions through their consideration in the House of Commons and the Senate.[4]

If certain commentary at the ENEV Committee meetings is any indication, another constitutional challenge to the IAA may be on the horizon.[5] Further, it remains to be seen if the Impact Assessment Agency will implement the revised legislation in a manner that addresses the varied criticisms of the IAA and the amendments – in particular, such that there is the certainty of process, timelines and designation criteria sought by proponents and investors alike.

A scheduled five-year review of the *Physical Activities Regulation*[6] ("Project List") also commenced in 2024. The IAA requires that the Project List be reviewed five years after coming into force. During this review, the Project List will be revised to reflect the IAA amendments, which require that activities defined as designated projects in the Project List be, in the Governor in Council's opinion, capable of causing adverse effects (i.e., non-negligible adverse changes) within federal jurisdiction, or direct or incidental adverse effects.

— ***Oil and Gas Sector Greenhouse Gas Emission Cap Regulations.*** On November 4, 2024, the government of Canada released its proposed ***Oil and Gas Sector Greenhouse Gas Emission Cap Regulations*** ("Emission Cap Regulations"), to be published in the forthcoming edition of the Canada Gazette, Part I. Issued under the ***Canadian Environmental Protection Act***, the Emission Cap Regulations will establish a cap-and-trade system that will apply to a wide range of industrial activities within the oil and gas sector, including onshore and offshore oil and gas production, oil sands production and upgrading, natural gas production and processing and liquefied natural gas ("LNG") production.

The Emission Cap Regulations represent additional emission-reduction requirements, and are over and above existing provincial emission reduction regimes, including Alberta's **TIER system**, the federal **Output-Based Pricing System, *Clean Fuel Regulations***, and the proposed **Clean Electricity Regulations**.

Under the cap-and-trade system, the Federal government will determine a maximum threshold for annual emissions and will freely issue emissions allowances in an amount equal to the cap. The Emission Cap Regulations, as set out, are to come into force on January 1, 2025 and will establish the initial cap based on 2026 emissions (attributed according to a formula set out in the Proposed Regulation). As a result, the cap for the first compliance period, from 2030 to 2032, will be 27% below 2026 attributed emission levels for affected facilities. This reduction is anticipated to correspond to a 35% decrease from 2019 emission levels.

Editor's Note: With the prorogation of parliament in January, the future applicability and scope of the Emission Cap Regulations is uncertain.

Covered Facilities

Facilities that carry out any of the prescribed industrial activities listed below ("Covered Facility") are caught by the Emission Cap Regulations:

— bitumen and other crude oil production activities, other than extraction of bitumen through thermal in situ recovery or from surface mining:

  — extraction, processing and production of light crude oil with a density of less than 920 kg/m^3 at 15°C; and

  — extraction, processing and production of bitumen or other heavy crude oil with a density greater than or equal to 920 kg/m^3 at 15°C;

— thermal in situ recovery of bitumen from oil sands deposits;

— surface mining of oil sands and extraction of bitumen;

4 ENEV Unrevised Meeting Transcripts from May 28, 30, and June 4, 2024.

5 In the ENEV Unrevised Meeting Transcript from June 4, Saskatchewan's Minister of Justice expressly stated Saskatchewan would consider bringing a constitutional challenge of the IAA if the amendments passed without further changes.

6 **SOR/2019-295**.

- upgrading of bitumen or heavy oil to produce synthetic crude oil;
- extraction of natural gas and natural gas condensates;
- compression of natural gas between production wells, natural gas processing facilities or re-injection sites;
- processing of natural gas or natural gas condensates into marketable natural gas and into natural gas liquids; and
- production of LNG.

Operator Obligations – Registration and Reporting

All operators of Covered Facilities must register by December 31, 2025. Operators of each Covered Facility are required to monitor and annually report production from each designated industrial activity carried out at that Covered Facility, as well as the quantities of GHGs (a) attributed to the facility and (b) from all specified emissions sources at the facility. Operators producing 30,000 or more barrels of oil (or the energy equivalent) in any month from the beginning of 2024 to July 2025, must start reporting emissions and production levels for 2026 by June 1, 2027. Operators that do not meet either of these criteria are required to begin reporting through the submission of an annual report no later than by June 1, 2029, for their 2028 emissions and production levels.

Compliance

Every operator is required to submit one compliance unit for each tonne of emissions produced. Under the Emission Cap Regulations, there are three categories of compliance units that operators may remit to cover their annual additional emission from Covered Facilities: (1) emission allowances; (2) decarbonization units; and (3) certain GHG offset credits.

Emissions Allowances

Each calendar year, the Minister of Environment will freely allocate to each Covered Facility emission allowances equal to their specific emission cap as calculated under the Emission Cap Regulations. Emission allowances are designed to be transferable, allowing operators within the cap-and-trade system to buy and sell them. There are no limits on the number of emissions allowances an operator can hold. Importantly, allowances obtained within this system cannot be used to meet obligations under other carbon pricing frameworks, including the OBPS. At least 80% of an operator's compliance units must be comprised of emission allowances. The remaining 20% may be comprised of GHG offset credits or a combination of decarbonization units and GHG offset credits, as described below.

Decarbonization Units

Akin to a fund credit under Alberta's **TIER Regulation**, operators may purchase "decarbonization units" to cover up to 10% of their emissions. The Emission Cap Regulations currently set the rate for decarbonization units at $50 per CO_2e tonne. Unlike pricing of fund credits under the TIER Regulation, the price per tonne of decarbonization units does not appear to be tied to the national carbon price.

GHG Offset Credits

Operators may use recognized offset credits to address up to 20% of their emissions. Currently, only offset credits issued under the ***Canadian Greenhouse Gas Offset Credit System Regulations***, or provincial offset credits recognized for use under the federal ***Output-Based Pricing System Regulations*** will be considered recognized GHG offset credits.

Remittance of Compliance Units

Operators that produce over an annual threshold of 365,000 barrels of oil equivalent ("Large Emitter") must not only report their production levels but also fulfill remittance obligations. A Large Emitter retains its status and the associated obligations unless its production drops below half the threshold (182,500 barrels) for four consecutive years. Remittance obligations require the operator to remit one "compliance unit" for each tonne of attributed GHGs during a compliance period.

A Large Emitter's total remittance for a compliance period is due by January 31 of the year that is two years after the compliance period (for example, if the compliance period is 2030-2032, the Large Emitter has until January 31, 2034 to submit its remittance obligations).

In addition, a Large Emitter has interim obligations to submit compliance units covering at least 30% of their GHG emissions for each of the first two years of any compliance period, due by January 31 of the year that is two years after that compliance year (for example,

for the 2030 compliance year during the 2030-2032 compliance period, a Large Emitter has until January 31, 2032 to remit compliance units equal to 30% of its GHGs during 2030).

New Covered Facilities are granted a five-year grace period from the start of their industrial activities before they become subject to remittance obligations under the Emission Cap Regulations. A new Covered Facility's attributed GHGs are deemed to be zero until January 1 of the year that is five calendar years after the year its industrial activities begin.

— **Bill C-59 – Environmental Amendments to the *Competition Act*.**[7] Federal Bill C-59[8] received royal assent on June 20, 2024. In addition to enacting the legislation for the Carbon Capture, Utilization and Storage Investment Tax Credit (as discussed further in our **Tax Incentives for Clean Energy** chapter), Bill C-59 implemented a number of important amendments to the ***Competition Act*** (the "Amendments") aimed at preventing "greenwashing" and unsubstantiated claims about environmental benefits.

Deceptive Marketing Provisions for Environmental Claims

The new anti-greenwashing provisions make it a deceptive marketing practice to: (i) make a representation in the form of a statement, warranty, or guarantee regarding a product/service's benefits for protecting or restoring the environment or mitigating the environmental and ecological effects of climate change that is not based on an adequate and proper test; or (ii) make a representation to the public with respect to the benefits of a business or business activity for protecting or restoring the environment or mitigating the environmental and ecological causes or effects of climate change that is not based on adequate and proper substantiation in accordance with *internationally recognized methodology*. If statements fall within the above parameters they would be offside the *Competition Act*'s deceptive marketing regime, potentially attracting significant civil administrative monetary penalties and damages, in additional to reputational impact.

The Competition Bureau (the "Bureau") released its **proposed guidelines** on December 23, 2024. In these guidelines, the Bureau defines "*internationally recognized methodology*" as a methodology to be internationally recognized if it is recognized in two or more countries. Further, the Bureau is of the view that the *Competition Act* does not necessarily require that the methodology be recognized by the governments of two or more countries. The proposed guidelines further state that substantiation does not necessarily involve testing in a lab, businesses should ensure

7 **R.S.C., 1985, c. C-34**.

8 **Bill C-59**: An Act to implement certain provisions of the fall economic statement tables in Parliament on November 21, 2023 and certain provisions of the budget tabled in Parliament on March 28, 2023.

that the methodology selected is suitable for the claim, having regard to all the relevant circumstances. Further, the guidelines make it clear that the focus is on marketing and/or promotional representations made to the public, and that representations made exclusively for a different purpose, such as to investors and shareholders in the context of securities filings, are outside the purview of the *Competition Act*'s deceptive marketing provisions. **Public consultation** on the proposed guidelines is open until February 28, 2025.

Private Rights of Action

The Amendments also grant, effective June 20, 2025, private parties the ability to seek leave to bring their own deceptive marketing applications to the **Competition Tribunal** ("Tribunal"), providing the ability for private parties to bypass the Bureau and bring directly to the Tribunal actions against a company for environmental claims and statements, either specific to a product/service or more broadly on a company's sustainability efforts and goals. Leave may only be granted where the application is "in the public interest"; this new test will have to be defined by the Tribunal.

Available remedies include temporary injunctive relief (to the extent the party seeking the order is able to show serious harm is likely to ensue unless the order is issued, the balance of convenience favours issuing the order and it must "appear" to the Tribunal that the conduct is in violation of the *Competition Act*) and orders to cease the relevant representations and claims, issue corrective notices, and/or pay administrative monetary penalties up to a maximum of 3% of worldwide revenues (with the exact penalty being subject to mitigating and aggravating factors).

Environmental Collaboration Antitrust Immunity Certification

The Amendments also introduced a certification regime to protect certain environmental collaborations from legal challenges. The certification regime exempts certain agreements relating to environmental initiatives from the civil and criminal collaborations provisions of the *Competition Act*. In order for the Bureau to grant such an exemption, it must be satisfied that: (i) the agreement is made for the purpose of protecting the environment; and (ii) the agreement is not likely to prevent or lessen competition substantially. The Bureau is to review these applications in a timely fashion (although there is no set timeline) and may place terms on the certificate. Once issued, the certificate must be registered with the Tribunal to exempt the arrangement from the conspiracy, bid-rigging and civil collaborations provisions of the *Competition Act*. Further details on the substance of the Bureau's review will follow from the Bureau in due course.

Impacts on Industry

Although the Bureau was already quite active with respect to potential greenwashing claims, many in the energy industry responded to the Amendments by promptly reviewing statements regarding their sustainability initiatives from websites and other public materials or providing relevant additional disclaimers in respect of same. Marketing and disclosing "green" initiatives and frameworks are now subject to greater scrutiny and risk, which the industry must navigate carefully. Hopefully, further Bureau guidance will provide sufficient clarity to guard from "greenhushing," being the avoidance of statements or disclosures regarding sustainability efforts, and corresponding disengagement from such efforts, to avoid greenwashing claims.

THE YEAR AHEAD

British Columbia

Hydrogen, Ammonia and Methanol Regulatory Developments. The BC Energy Regulator will continue to develop regulatory policies in response to the *Energy Statutes Amendment Act,* which granted it oversight over the manufacturing, associated on-site storage and pipeline transportation of hydrogen, ammonia and methanol in B.C. **Over the last year**, the BC Energy Regulator has sought feedback on proposed regulatory policies for pipelines and manufacturing facilities for hydrogen, ammonia and methanol. The next phase of engagement planned for the spring and summer of 2025 may include the development of policies respecting financial assurance, liability management, remediation and reclamation obligations and cost recovery. Eventually, this work will lead to drafting and potential implementation of regulations for these industries.

New Standards to Curb Upstream Oil and Gas Emissions. In a further effort to address methane emissions in accordance with the CleanBC Roadmap to 2030, amendments to the ***Drilling and Production Regulation, the Oil and Gas Processing Facility Regulation and the Pipeline Regulation*** will become effective January 1, 2025. These amendments seek to achieve further reductions in methane emissions from B.C.'s upstream oil and gas sector by imposing leak detection and repair requirements and regulating specified emissions sources, such as compressors seals, pneumatic pumps and devices, and surface casing vent flows.

— **Ongoing Proceedings on the Ambit of "Public Utility."** In each of *Richmond (City) v. British Columbia (Utilities Commission)*, 2024 BCCA 399 and *Powell River Energy Inc. v. British Columbia (Utilities Commission)*, 2024 BCCA 327, the B.C. Court of Appeal granted leave to appeal to the applicants in respect of the ambit of the meaning of "public utility" under the *Utilities Commission Act*. Accordingly, we can expect further clarification from the courts on the breadth of public utility in that context.

Alberta

— **Continued Tension with Federal Government:** With the federal *Clean Electricity Regulations* coming into force and the release of the proposed Emission Cap Regulations, we anticipate the recently announced second challenge to the *Impact Assessment Act* may not be the only environmental legislation challenged by Alberta. The outcome of these challenges will impact energy policy across the country and across a number of industries.

Editor's Note: In light of the suspension of parliament and a pending federal election, a change in federal government may impact the energy policy landscape in Canada and relations among the provinces and the Federal Government as it relates to, among other things, energy and environmental regulations.

— **Details on New Requirements for Power Plant Development:** An area to monitor in Alberta will be the new requirements for power plant applications before the AUC, including those with respect to the siting of projects on agricultural lands, irrigability assessments, viewscapes and the end of life and reclamation security requirements.

Ontario

— **Ontario's Affordable Energy Future: The Pressing Case for More Power:** In October 2024, the Ontario government released its latest energy policy statement, which sets out plans to meet growing electricity demand with a "pro-growth agenda that takes an all-of-the-above approach to energy planning, including nuclear, hydroelectricity, energy storage, natural gas, hydrogen and renewables and other fuels." According to the IESO, Ontario's demand for electricity is forecast to increase by 75% by 2050. The policy statement sets out directions for its future growth agenda and sets out a list of priorities that may be relevant when considering future energy investments, including:

  — Extending Ontario's clean energy advantage through baseload energy resources and a "cadence of competitive long-term procurement" to build

new energy resources at lowest cost.

- Continuing to expedite transmission infrastructure development through "enhanced transmission planning and pre-development activities."
- Establishing a Natural Gas Policy Statement, prioritizing an "economically viable natural gas network," and exploring opportunities to increase clean fuel production.
- Providing early and meaningful engagement and consultation on energy planning, and delivering continued capacity funding and support for Indigenous ownership and participation in energy projects.
- Strengthening local energy planning through municipal guidance, support, and capacity building, and establishing better alignment with the province's planning process.
- Exploring opportunities to help other jurisdictions address anticipated shortfalls and meet their clean energy commitments and consider opportunities for trade through new and expanded interties.

The policy statement also shapes the government's first ***Integrated Energy Resource Plan***, which is set to be released in 2025.

Québec

- **Further Consultation on Bill 81:** Bill 81 is still at the presentation stage before the National Assembly of Québec and modifications to the Bill are expected in the coming months. In addition to proposing to amend the majority of Québec's environmental legislation, if adopted, Québec's expanded legislated zero emission vehicle sales mandate will be the first of its kind in Canada, setting a precedent for other provinces and the federal government.

Federal

- **Constitutional Challenges:** The federal government may see additional constitutional challenges to the federal *Impact Assessment Act*. Late in November 2024, Alberta filed a second reference case to the Alberta Court of Appeal to rule on the constitutionality of the amended *Impact Assessment Act*. Whether other provinces back Alberta's legal challenges is an area to watch in 2025. Further, the outcome of the upcoming federal election could change Alberta's strategy with respect to these challenges.
- **Review of the *Physical Activities Regulation* under the Federal *Impact Assessment Act*:** In 2025, we expect the release of a new Project List which reflects the results of the Project List review. The Impact Assessment Agency of Canada will use the input provided on the Project List to inform recommendations which will be set out in a report to the Minister of Environment and Climate Change. This report must consider feedback received from stakeholders, Indigenous partners and the public. Proposed regulatory changes resulting from the Project List review will follow the usual regulatory development and approval process for Governor in Council Regulations, including publishing draft regulatory text through Canada Gazette, Part I for further consultation opportunities.
- **Emissions Cap Update:** The federal government sought written feedback on the proposed Emission Cap Regulations from November 9, 2024, to January 8, 2025. The **Backgrounder** released by the federal government with the proposed Emissions Cap Regulations suggests that the Emissions Cap reflects, in the federal government's view, technically achievable reductions based on the federal government's assessment of abatement technologies that can be feasibly deployed within the oil and gas sector by 2030-2032. While it remains to be seen whether the Emissions Cap can be achieved through the deployment of abatement technologies, the proposed Emissions Cap Regulations add another layer of complexity to emission reduction obligations. However, with Parliament prorogued until March 24, 2025 and a federal election looming in the spring, the Emission Cap Regulations may never come into force.

Guidance on *Competition Act* Amendments: Additional guidance from the Bureau on the interpretation of the Amendments was released on December 23, 2024 via the **proposed guidelines**. The Bureau is launching a public consultation to solicit feedback from Canadians on its proposed guidelines concerning environmental claims. This follows an initial round of consultations held during the summer of 2024. The Bureau invites interested parties to provide feedback on its **proposed guidelines before February 28, 2025**. Following this consultation, the Bureau proposes to publish final guidelines.

ABORIGINAL LAW

By Bryn Gray, Selina Lee-Andersen, Daphne Rodzinyak, Riley Thackray and Nico Rullmann

Aboriginal Law

There were several developments in Aboriginal law and policy in 2024 that impact power project development and the broader energy sector in Canada. This includes continued momentum in Indigenous equity ownership in energy projects and associated loan guarantee programs, as well as notable cases relating to the duty to consult and appellate confirmation that proponents can be liable in nuisance for impacts to established Aboriginal harvesting rights that are not authorized by governments.

CONTINUED MOMENTUM IN INDIGENOUS EQUITY OWNERSHIP

There were a number of developments to encourage and support the ongoing trend of increased Indigenous equity project investments in Canada in 2024 particularly in the energy sector. This includes new provincial power calls that mandate Indigenous equity ownership participation as well as the introduction of new Indigenous loan guarantee programs to help support Indigenous equity investments in projects.

Federal

On April 16, 2024, the federal government **presented** "Budget 2024: Fairness to Every Generation," which included further details on the long-awaited federal Indigenous Loan Guarantee Program ("FILGP"). In Chapter 6, titled "A Fair Future for Indigenous Peoples," the government outlined the preliminary structure for the FILGP, which is designed to improve Indigenous communities' access to cost-effective capital, fostering their participation as equity owners in various natural resource and energy ventures. The FILGP will offer up to C$5 billion in total loan guarantees to Indigenous communities interested in investing in various natural resource and energy projects nationwide. This sector-neutral strategy is designed to ensure benefits for Indigenous communities in all regions of Canada. Budget 2024 clarifies that Indigenous governments and their wholly owned entities will be recognized as eligible applicants. However, further details on the criteria for project evaluation have yet to be disclosed.

British Columbia

On February 22, 2024, the British Columbia government **announced** its plans to roll out a provincial First Nations Equity Financing Framework ("Framework"). This initiative, which was set out in the Province's 2024 Budget and Fiscal Plan, is designed to enhance the formation of economic partnerships between First Nations communities and the broader business world. The Framework will review a wide range of proposals, including those from the natural resource sector, with an aim to support First Nations equity investments through equity loan guarantees among other financial instruments, with a cumulative guarantee limit of $1 billion. To facilitate the Framework, the 2024 Budget announced the creation of a" $10 million First Nations Equity Financing special account to address the immediate capacity needs of First Nations groups interested in acquiring equity positions in key projects and to cover the provincial expenses associated with kick-starting a new loan guarantee program.

In addition to launching a new provincial loan guarantee program, British Columbia Hydro and Power Authority ("BC Hydro") **issued** a request for proposals on April 3, 2024 entitled *BC Hydro Call for Power 2024* to acquire approximately 3,000 gigawatt hours per year of electricity. This was BC Hydro's first competitive call for power in 15 years and it mandates that a minimum 25% First Nation equity ownership must be in place by a project's commercial operation date. For further details on the BC Hydro Call for Power, see our **British Columbia Overview chapter**.

SaskPower

On June 27, 2024, Saskatchewan Power Corporation ("SaskPower") **announced** an agreement with First Nations Power Authority ("FNPA") to find a proponent to develop, own and operate a 100-megawatt solar generation facility to be located in south-central Saskatchewan, which is expected to be online by late 2028. FNPA will seek an independent power producer to design, construct, own and operate the facility. The process provides that the successful proponent must have at least 30% First Nations ownership.

MANITOBA

On September 20, 2024, the Government of Manitoba **introduced** its Affordable Energy Plan, which aims to address the province's clean energy needs. According to the plan, Manitoba Hydro has identified a requirement for an additional 600 megawatts of wind power to provide residents with cost-effective and reliable energy. To meet this goal, Manitoba Hydro is planning to request proposals for new wind projects that will mainly be owned by Indigenous groups. The provincial government is also setting up a loan guarantee program to help Indigenous communities get involved in the wind power sector. This program will be set up to work alongside federal tax incentives to increase financial support for wind projects led by Indigenous communities. More information about the specifics of the loan guarantee program is expected to be released in the Manitoba 2025 Budget.

In addition to the above new initiatives, the Ontario government has also announced a review of its Aboriginal Loan Guarantee Program which was launched in 2009 and supports Indigenous participation in electricity infrastructure projects, including renewable energy infrastructure and transmission projects. Public comments and feedback on the program are due by January 12, 2025 and we expect the review will lead to the further expansion of this program.

B.C. RECOGNITION OF ABORIGINAL TITLE ON HAIDA GWAII

On April 14, 2024, the Province of British Columbia ("Province") and the Council of the Haida Nation **announced** the signing of an agreement recognizing the Haida Nation's Aboriginal title over Haida Gwaii, an island region of approximately 10,000 square kilometres off the northern coast of British Columbia. The ***Gaayhllxid/ Gíihlagalgang "Rising Tide" Haida Title Lands Agreement*** ("Agreement") affirms Haida title and jurisdiction over Haida Gwaii under section 35 of the *Constitution Act*, 1982 while aiming to maintain the rights associated with fee simple land ownership. The Agreement is novel in a number of respects and raises numerous questions by its lack of detail and provisions that are inconsistent with publicly stated intentions and assurances by the province. The Agreement recognizes section 35 rights yet the federal government is notably a party and the Agreement itself is not a treaty. While the province has taken the position that the Agreement protects existing fee simple interests, the Agreement introduces significant uncertainty for fee simple landowners on Haida Gwaii and those who rely on

Crown land authorizations due to conflicting terms and the lack of clear protections of existing interests. It remains to be seen whether this type of provincial agreement will be unique to Haida Gwaii (where there are no overlapping title interests unlike almost all other title claims in B.C.) or whether the re-elected B.C. government will attempt to enter into similar agreements with other Indigenous groups with title claims in B.C.

CASE LAW UPDATES

B.C. Court of Appeal Confirms Proponents Can Be Liable in Nuisance for Unreasonable Interference with Aboriginal Rights if Impacts Are Not Authorized by Governments

In *Thomas v. Rio Tinto Alcan Inc.*, **2024 BCCA 62**, the B.C. Court of Appeal ("BCCA") largely upheld a decision by the Supreme Court of British Columbia ("BCSC"), which dismissed a claim by two B.C. First Nations against the owner/operator of a hydroelectric dam for nuisance and breach of riparian rights. The BCSC recognized that tort claims could be brought against a non-government entity for interference with established Aboriginal rights but dismissed the claim after finding that the company had complied with all applicable regulatory requirements in constructing and operating the dam, establishing the defence of statutory authorization. The BCCA confirmed these findings, but varied the declaratory relief granted by federal and provincial governments to more clearly specify the nature of their duties associated with the First Nations' section 35 right to fish. Leave to appeal to the Supreme Court of Canada was denied.

As we reported in **the 2023 edition of Power Perspectives**, this case centred on the Kenney Dam, built to produce hydropower for aluminum smelting following legislative authorization by the B.C. government in the 1950s. The Saik'uz and Stellat'en First Nations ("First Nations") brought a common law claim in nuisance and breach of riparian rights on the basis that the dam's alteration of water flow had significantly impacted their section 35 Aboriginal rights, title and fisheries. The First Nations sought injunctive relief to restore more natural water flow to the Nechako River as well as damages, but they did not pursue damages at trial.

At the BCSC, Justice Kent found that the First Nations' interest in and occupancy of their reserves, together with their section 35 right to fish, were sufficient to ground a common law claim in nuisance. He held that Aboriginal rights can ground a nuisance claim – which requires a non-trivial and unreasonable interference with property rights – because Aboriginal rights are closely related to a particular piece of land. Justice Kent found that construction and operation of the dam had negative impacts on the abundance and health of certain fish populations in the watershed, in turn negatively impacting the First Nations Aboriginal right to fish. He declined to make a finding

of Aboriginal title because of insufficient evidence to determine exclusivity with regard to overlapping Aboriginal title claimants.

However, the proponent was not liable for nuisance because its operation of the dam was authorized by the government and in compliance with all regulatory requirements. The statutory authorization defence applies where a tort is the inevitable result of exercising power authorized by Parliament or the Legislature; here, the Kenney dam was approved by all levels of government and Justice Kent found that always operated within the parameters of its authorization. He rejected the argument that the defence was not available because of the constitutional nature of the right underlying the nuisance claim.

Justice Kent granted declaratory relief against the provincial and federal governments, stating that each have an ongoing duty and obligation to protect the First Nations' Aboriginal right to fish.

The BCCA upheld the bulk of Justice Kent's decision, only varying the declaratory relief against the government defendants. This is the first appellate decision in Canada that confirms that a private law nuisance claim can be founded on a section 35 Aboriginal harvesting right, rejecting the argument that a fishing right cannot ground a nuisance claim given it is not a proprietary right. The BCCA emphasized that a "broader perspective" on common law rules regarding property is required when considering section 35 claims in the context of the unique or *sui generis* rights of Indigenous peoples protected by the constitution. However, the BCCA clarified that this particular right successfully grounded a tort claim because it was area/land-specific; the BCCA left open for another day the question of whether a section 35 by itself – without any connection to land – can ground a claim in nuisance.

The BCCA upheld Justice Kent's application of the statutory authorization defence despite the constitutional nature of the Aboriginal rights at issue. The BCCA emphasized that First Nations rights and remedies lie against the Crown for harms related to any infringement of their constitutional rights caused by government authorizations. Where section 35 rights ground common law tort claims such as nuisance, common law defences remain available.

The BCCA also clarified what it means for a nuisance to "inevitably result" from statutory authorization. Generally, an inevitable result arises when there is a necessary causal connection between the authorized work and the nuisance. Some courts, however, have considered whether there was a "practical feasible alternative" to the work in question. The BCCA clarified that here, no consideration of "practical feasible alternatives" was required because the legislation authorized the Kenney Dam specifically, did not grant discretion to the proponent to conduct the work differently, and contemplated a nuisance flowing from the authorized works.

Finally, the BCCA considered the sufficiency of the declaratory relief granted by Justice Kent. Given the ongoing harm the Kenney Dam caused to the appellants' constitutional rights, the BCCA found that declaring that the federal and provincial governments "have an obligation to protect" the First Nations' section 35 right to fish in the Nechako River watershed was an "unduly narrow approach" to declaratory relief that gave "no real practical utility" to the First Nations. There remained ongoing and future impairment Aboriginal right to fish that could be affected by both governments' continued involvement in annual decision-making with respect to the flow regime of the Kenney Dam and Nechako River watershed, even though no monetary liability was found. The BCCA held that the recognition of an Aboriginal rights to fish in the Nechako River watershed imposes a positive obligation on both the federal and B.C. government to protect that right.

The BCCA thus issued new relief that recognized a fiduciary duty of B.C. and Canada going forward with respect to the annual water allocation and flow regime in the Nechako River, declaring that both levels of government have a duty to consult whenever they contemplate an action or decision that carries the potential for a novel adverse impact on the appellants' exercise of their section 35 right to fish. The BCCA also stated that the two levels of government must ensure that their continued management of the annual water allocation and flow regime is substantively consistent with the requirements of section 35 of the *Constitution Act, 1982* but noted that what this requires will be informed by the fact that this is an Aboriginal right and not title to land.

This decision has significant potential implications for future claims by Indigenous groups against private proponents for impacts to established Aboriginal and treaty rights as well as the obligations of government entities, although the defence of statutory authorization may significantly shield third-party proponents depending on the circumstances. Even where private law liability does not arise, associated declaratory relief could still impact future decision-making which could in turn affect the future operations of the specific project at issue.

Share Purchase of Mining Company Insufficient to Trigger the Duty to Consult

In *Skii km Lax Ha v. British Columbia (Chief Executive Assessment Officer)*, **2024 BCSC 1687**, the BCSC dismissed a petition brought by the Tsetsaut / Skii km Lax Ha Nation ("TSKLH Nation") against the Province of British Columbia and Pretium Resources Inc. ("Pretium") alleging that the Province failed to consult following a share purchase of Pretium by Newcrest Mining Ltd ("Newcrest"). Pretium holds an environmental assessment certificate ("EA Certificate") and associated permits and authorizations, including a major mine permit under the *Mines Act*, **RSBC 1996, c 293**, to operate the Brucejack Mine located in northwestern British Columbia and within the asserted territory of the TSKLH Nation.

Pretium, previously a publicly traded company, became wholly owned by Newcrest in March 2022 through a share sale pursuant to a court-appointed plan of arrangement. Following the share acquisition, Pretium amalgamated with a Newcrest subsidiary to create Pretium Resources Inc. While Pretium became a Newcrest subsidiary, it continued as a legally distinct entity that continued to hold the assets, EA Certificate and other mine permit authorizations associated with the Brucejack Mine. The day-to-day operations of Pretium, including relations with the TSKLH Nation, largely remained unchanged.

Following the share acquisition, Pretium did not apply to transfer the EA Certificate, the major mine permit or any of the other authorizations and permits it holds in relation to the Brucejack Mine. Once an EA Certificate has been issued, an EA Certificate holder may seek the approval of the Chief Executive Assessment Officer ("CEAO") for a transfer of the EA Certificate. Section 5 of the EA Certificate for the Brucejack Mine required that, prior to "transferring a significant interest in the Project," the EA Certificate holder and proposed transferee must obtain consent from the CEAO and apply under the *Environmental Assessment Act*, **SBC 2018, c 51**, for an amendment to the EA Certificate.[1] Under the **Transfer Policy Guidelines**, consent from the CEAO is required "if either the entire project is transferred or where the holder transfers interests necessary to implement the project according to the EA Certificate or Order conditions."

In response to TSKLH Nation's assertion that the acquisition triggered the duty to consult, the CEAO wrote to the TSKLH Nation advising that the share purchase was not the type of change in a "significant interest" that triggered the transfer provision of the EA Certificate. The CEAO noted that Pretium will: (i) continue to exist and hold the EA Certificate and its interest in the Brucejack Mine following the completion of the transaction; and (ii) continue to be responsible for ensuring it is compliant with the EA Certificate and conditions. The TKLH Nation argued in their petition that (i) the CEAO was compelled to contemplate the transfer, amounting to Crown conduct requiring consultation with the TSKLH Nation; and (ii) the Province's failure to consult was therefore a breach of TSKLH Nation's section 35 rights.

The BCSC concluded that it was reasonable for the CEAO to consider: (i) that Newcrest's purchase of Pretium's shares was not the type of change in a "significant interest" that triggered a requirement for a transfer application; and (ii) that no transfer application was required where the corporate holder of an EA Certificate remains the same after the purchase of its shares, and the corporate assets have not been sold. On its face, the legislative scheme around the transfer of EACs is primarily concerned with the operational fulfilment of the project conditions, not changes to organizational or ownership structure.

With respect to the duty to consult analysis, the BCSC assumed, without deciding, that the CEAO's conclusion that no transfer application was required was capable of amounting to contemplation of Crown conduct. However, the BCSC found that there was no potential to cause an appreciable adverse effect on the rights and title claims of the TSKLH Nation. Pretium, as the holder of the EA Certificate, continued to be bound by all of the conditions of the certificate and other related permits, including being legally bound to comply with all of the EA Certificate terms of benefit to the TSKLH Nation. While the TSKLH Nation argued that the acquisition resulted in a suspension of the benefit-sharing agreement negotiations relating to the Brucejack Mine, thereby diminishing promises made in an Aboriginal Conultation Plan prepared under the EA Certificate, the BCSC found that any delay in negotiations was attributable to the sale of shares and not caused by Crown conduct. In any event, the three-month pause in negotiations did not give rise to an appreciable adverse effect.

While this case affirms that the duty was not triggered by a share sale, it is still important to consider duty to consult issues in the context of acquiring entities that hold EACs or other various permits as each duty to

1 Under the 2002 *Environmental Assessment Act*, **SBC 2002, c 43**, requirements in relation to transfers of interest in a project were included directly in EA Certificates; however, under the 2018 *Environmental Assessment Act*, **SBC 2018, c 51**, requirements for a transfer of an interest in a project are now addressed in ss. 32–33 of the Act and in a related policy document, the **Transfer Policy and Procedures**, issued in June 2021.

consult determination is fact specific. The structure of the transaction could give rise to different considerations, such as an asset sale as any associated Crown approvals would be Crown conduct that could trigger the duty. This does not, however, mean that a duty would be triggered by an asset sale. If there are no anticipated changes to the operations of the project, similar arguments could be advanced regarding a lack of impact to Aboriginal or treaty rights as there is no novel impact to trigger a duty.

Consultation in the Face of Competing Claims and Overlapping Territories

The courts have recently seen a growing number of disputes between Indigenous groups with respect to consultation obligations owed regarding competing claims and overlapping territories. Such disputes may arise from a variety of reasons, including evolving territorial claims and disputes related to same, disputes between First Nations and Metis groups, and concerns about the distribution project benefits. While it is the Crown's responsibility to determine who needs to be consulted for a given project, these issues can raise significant challenges for proponents when engaging with Indigenous groups that are involved in such disputes. In general, the courts have thus far typically declined to weigh in on these disputes in a consultation context given that consultation is not a rights-determination exercise and that credibly asserted rights are sufficient to trigger the duty although each determination has been based on the specific facts at issue.

A recent example of judicial consideration of such a dispute was *McLeod Lake Indian Band v. West Moberly First Nations*, **2024 BCCA 187**, which the B.C. Court of Appeal considered the dismissal of a request by the McLeod Lake Indian Band ("MLIB") sought to be added as a respondent to a judicial review commenced by the West Moberly First Nations ("WMFN"). The WMFN challenged the adequacy of the Province of British Columbia's consultation in relation to forestry activities undertaken by third-party proponents in Treaty 8 territory. MLIB, another Treaty 8 First Nation, was satisfied with the adequacy of consultation it received in relation to the forestry activities, but argued that the WMFN judicial review proceeding may adversely impact the exercise of its Treaty rights and disputed that the WMFN had rights in connection with the territory in which the proposed activities were located. The MLIB alleged that WMFN has asserted rights that have gradually and increasingly encroached into MLIB's claimed traditional territory and voiced concerns that a judge hearing the judicial review would, of necessity, have to address the strength of WMFN's claim of Aboriginal rights, which may result in findings or observations that could prejudice MLIB's exercise of its treaty rights.

The BCCA upheld the BCSC's decision that MLIB ought not to be added as a respondent as the potential impacts identified by MLIB were "at best, speculative and indirect" and MLIB's application was "advanced on the faulty premise that Crown consultation is a finite resource that can only be allocated in limited measures." The BCCA confirmed that the Province's consultation with the WMFN is premised upon WMFN's asserted rights, and not on any recognition of established title or rights, and any findings on consultation would not prejudice MLIB's own claim to the same lands.

A similar challenge has been launched in Ontario by Netmizaaggamig Nishnaabeg ("NNFN") (formerly known as Pic Mobert First Nation). NNFN recently commenced a judicial review in the Ontario Superior Court of Justice of decisions by Ministry of Mining officials to add, and refuse to remove, two additional First Nations from consultation lists compiled and utilized by the Crown concerning regulatory decisions relating to two mines in NNFN's asserted traditional territory. The First Nation alleges that the decision to add the two additional First Nations on the consultation list unreasonably allows those First Nations be involved in mining decisions that relate only to NNFN, thereby prejudicing NNFN's rights. The judicial review has yet to be determined.

This issue is also arising in the context of the settlement of claims that are challenged by other First Nations. In *Cold Lake First Nations v. Canada (Attorney General)*, **2024 FC 925**, Cold Lake First Nation ("CLFN") sought judicial review of Canada's decision to enter into settlement with Buffalo River Dene Nation and Birch Narrows Dene Nation regarding the establishment of the Cold Lake Air Weapons Range ("Range"). In 2002, CLFN entered into a settlement with Canada on the basis that the establishment of the Range displaced many members who used the land for traditional sustenance. As part of Cold Lake's settlement, the Nation was granted access to parts of the Range and Canada agreed to consult CLFN before granting access to anyone else. Canada's recent settlement with Buffalo River Dene and Birch Narrows Dene similarly involved granting these Nations access to parts of the Range.

The Federal Court dismissed CLFN's application, holding that the duty to consult does not provide CLFN the right to be consulted regarding another Indigenous community's *entitlement* to access the Range nor to question the grounds on which Canada decides to settle another community's claim. The Federal Court noted that CLFN's submissions failed to provide concerns in any particularity related to scarce resources or loss of economic opportunities that may result from the CLFN's access to the Range. As such, while the Federal Court confirmed that the scope of the duty to consult does not extend to the entitlement of other First Nations to their asserted rights or title, it acknowledged that, in cases where two Indigenous communities are making claims to the same finite resource, the duty to consult may be triggered if the Crown proposes to recognize or grant rights to that resource to one community and such conduct is likely to adversely impact the other community's exercise of its rights.

The issue of Indigenous communities disputing Crown recognition of rights of another Indigenous community also arose in the context of Bill C-53: ***Recognition of Certain Métis Governments in Alberta, Ontario and Saskatchewan and Métis Self-Government Act.*** Bill C-53 was introduced by the Minister of Crown-Indigenous Relations in June 2023 to give effect to treaties with Métis governments in Alberta, Ontario and Saskatchewan and to provide a framework for the implementation of those treaties. The bill has received wide criticism from First Nations and other Métis groups in Canada. In particular, many First Nations in Ontario reject the recognition of certain Métis communities in Ontario and believe that the legislation devalues and will have negative impacts their rights. There has also been criticism of Bill C-53 by certain Métis groups. Some Métis in Alberta reject the Métis Nation of Alberta ("MNA") government's authority and assert the bill takes away their rights to self-determination and consultation and the Métis Nation of Saskatchewan withdrew their support for the bill as it was a one-size-fits-all approach that did not recognized the unique context of the Métis Nation of Saskatchewan. The federal government recently confirmed that the Bill as currently drafted will not move forward although it is unclear whether the federal government will attempt to amend the legislation.

In addition to the criticism of Bill C-53, the Dakota Tipi and Canupawakpa Dakota First Nations in Manitoba recently commenced an injunction relating to the Red River Métis Self Government Recognition and Implementation Treaty signed by the Manitoba Métis Federation and the Government of Canada. The Dakota Nations have alleged that Canada has breached constitutional and fiduciary obligations in signing the treaty, including the duty to consult, although the treaty does include a specific provision indicating that nothing the in Treaty impacts any section 35 rights of another Indigenous collectivity.

These disputes are not limited to Indigenous groups within Canada. Following the Supreme Court of Canada's decision in *Desautel,* a number of Indigenous groups in the United States have asserted section 35 rights in Canada and that they are owed a duty to consult with respect to certain projects in Canada. This has led to several First Nations in Canada objecting to the consultation of U.S. Tribes in specific project reviews as the First Nations dispute the legitimacy of the Tribes' assertions in Canada.

These disputes raise important issues and nuances that proponents must be attuned to when consulting with potentially impacted First Nation and Métis groups, particularly when determining which groups are owed

consultation and navigating the sensitivities of potential competing claims or overlapping territories that may be at play in the relevant area.

Procedural Fairness and Legitimate Expectations Results in Further Consultation Owed to First Nations

In *Benga Mining Limited v. Canada (Environmental and Climate Change)*, 2024 FC 231, the Federal Court set aside the decisions of the Minister of Environment and Climate Change and Cabinet denying approval of the Grassy Mountain Coal Project, finding that the Piikani Nation and Stoney Nakoda ought to have been afforded additional consultation. Piikani Nation and Stoney Nakoda supported the project on the basis that it would provide economic, social, and cultural benefits, employment and commercial opportunities, and allow the First Nations to act as environmental stewards in partnership with Benga Mining to oversee the project and its reclamation.

The First Nations challenged the decisions denying the project arguing, *inter alia*, that they ought to have been afforded further consultation opportunities to advance their interests related to the project, including the economic opportunities and impact benefit agreements. Specifically, they argued that their right to procedural fairness was breached because they were promised additional consultation, which was not fulfilled. Their argument was based on a news release issued by the Impact Assessment Agency of Canada that stated: "[p]rior to the Government of Canada's decision on the project, the Impact Assessment Agency of Canada (the Agency) will consult with Indigenous groups on the Joint Review Panel's report."

The Federal Court agreed with the First Nation applicants that, based on the news release, they had legitimate expectations that they would receive the benefit of further consultation before the denial decisions were made. The court found that, once the news release gave rise to a legitimate expectation that such procedure would be followed, that procedure was required by the duty of fairness and the First Nations were entitled to take advantage of the opportunity afforded by that procedure to advance their arguments based on economic opportunities in an effort to influence the outcome of the decisions. As the First Nations were not afforded the consultation opportunity that the news release represented they would receive, their right to procedural fairness was breached.

The Federal Court declined to conduct an analysis under the constitutional duty to consult as the First Nations' arguments under administrative law and the right to procedural fairness were determinative of the outcome. The Federal Court's decision serves as a reminder that consultation with Indigenous groups can also be impacted by and based on principles of procedural fairness – and that commitments for further consultation can lead to decisions being quashed if that further consultation is not provided.

CASES TO WATCH

Challenge to Plan Implemented under Blueberry Implementation Agreement

In July of 2024, Blueberry River First Nations ("BRFN") commenced a lawsuit against the Province of British Columbia (*Blueberry River First Nations v. His Majesty the King in Right of the Province of British Columbia* (9 July 2024), Vancouver 244500 (BCSC)) challenging the province's decision to move forward with an implementation plan on resource development. After the BCSC found the Province of British Columbia had infringed upon Blueberry River's Treaty 8 rights due to the cumulative impacts of decades of industrial development, the province and BRFN reached a historic agreement on January 18, 2023 for future management of cumulative effects and development as well as compensation for past impacts ("Implementation Agreement"). The Implementation Agreement included a series of measures to protect BRFN's treaty rights, including significant decision-making powers for BRFN and land protections in high-value areas via limitations on new developments in certain areas – called New Disturbance Caps.

On May 30, 2024, the Province of British Columbia announced that it and BRFN were moving forward under the Implementation Agreement by proceeding with the "Gundy High Value 1 Plan" ("Gundy Plan"), which sets out more detailed land protections and development approval mechanisms to be piloted over three years. At the time of writing, the Gundy Plan is not yet publicly available.

However, in July 2024, BRFN filed a Notice of Civil Claim ("Civil Claim") in the BCSC alleging that the Gundy Plan is not in BRFN's best interests because it removes the New Disturbance Caps in a manner which would require amendment of the Implementation Agreement, which has not occurred. The Civil Claim also alleges that the Gundy Plan was approved without the authorization of the majority of BRFN's Chief and Council, contrary to BRFN's governance model and the terms of the Implementation Agreement. BRFN councillors have subsequently removed their Chief from office following an independent investigation that allegedly confirmed that she unilaterally approved five development permits in July 2023, contrary to BRFN bylaws which require majority approval. The Chief has since filed a judicial review of BRFN's decision in Federal Court.

In the Civil Claim, BRFN seeks declaratory and injunctive relief against the Province of British Columbia, including injunctive relief to prevent the BC Energy Regulator from taking any further steps with respect to the Gundy Plan. The new litigation raises significant questions about BRFN governance and the ability of BRFN and the B.C. government to implement the complex decision-making arrangements and initiatives contemplated by the Agreement. This has further increased the already significant regulatory uncertainty in this area of B.C. contrary to the stability and certainty promised when the Implementation Agreement was announced.

Update on Cross-Country Cumulative Impact Claims

As discussed in the 2023 edition of **Power Perspectives**, several First Nations across Canada have filed claims against provincial and federal governments alleging infringement of treaty rights by way of the cumulative impacts of government-authorized industrial developments on traditional territories. These cases seek to build on the BCSC's ruling in *Yahey v. British Columbia*, **2021 BCSC 1287**, which we discussed in the 2022 edition of **Power Perspectives**. Here, we provide updates on notable developments in these actions.

Duncan's First Nation ("DFN") filed a statement of claim in 2022 relating to the infringement of Treaty 8 harvesting rights from cumulative impacts. This is the same treaty that was at issue in *Yahey* but the claim is brought by an Alberta First Nation and therefore is before the Alberta court and is considering the management of cumulative impacts by the Alberta rather than B.C. government. It advances many of the same grounds and seeks similar relief, including that Alberta's mechanisms for assessing cumulative impacts are lacking and have contributed to the breach of its obligations under Treaty 8, and seeks an order prohibiting Alberta from permitting any activities that further infringe DFN's treaty rights and breach Alberta's fiduciary obligations to DFN. The parties are currently engaged in document production, intended to be completed in January 2025, and the parties agreed to discuss and apply for trial dates by November 30, 2024.

Beaver Lake Cree Nation ("BLCN") filed a claim in 2008 against the Alberta and federal governments, claiming that the cumulative impacts of industrial development within their territory amounted to a breach of Treaty 6. In 2024, after BLCN's successful appeal for advanced costs at the Supreme Court of Canada, the Court of King's Bench of Alberta awarded BLCN advance costs against Alberta. BLCN and Canada settled the advance costs application as against Canada out of court. The trial in this matter is planned for 2026.

TAX INCENTIVES FOR CLEAN ENERGY

By Matt Kraemer and Adam Unick

Tax Incentives for Clean Energy

Over the past few years, the Federal Government of Canada ("Government") has introduced the investment tax credits to promote investment in clean technology in Canada ("Clean Economy Tax Credits").

2024 marked a significant milestone for the Clean Economy Tax Credits as Bill C-59 and Bill C-69 received royal assent. Budget 2024 also introduced new electric vehicle supply chain investment tax credit (the "EV ITC"), additional implementation and design particulars for the clean electricity investment tax credit (the "CE ITC"), and provided further modifications to the now-enacted Clean Economy Tax Credits.

On August 12, 2024, the Department of Finance released proposed draft legislation for a number of previously announced proposals ("August 12 Proposals"), including draft legislation relating to the CE ITC.

On December 16, 2024, the Government presented the 2024 Fall Economic Statement ("**Fall Economic Statement**") in the House of Commons. The Fall Economic Statement included notable updates to the design and delivery of certain of the Clean Economy Tax Credits including the CE ITC, the EV ITC and the Clean Hydrogen Investment Tax Credit ("CH ITC").

> **Editors' note:** *As a result of the prorogation of Parliament on January 6, 2025, there is significant uncertainty regarding whether certain of the Budget 2024 and Fall Economic Statement proposals will be passed into law. The proposed introduction of the clean electricity investment tax credit and electric vehicle supply chain investment tax credit are in significant jeopardy of never being passed into law. Further, it is questionable whether proposals to expand the property eligible for the clean technology investment tax credit, clean technology manufacturing investment tax credit and the clean hydrogen investment tax credit will be advanced. At this time it is unclear whether such proposals will go ahead in the next session of Parliament or ever become law. This uncertainty is further compounded by the fact that 2025 is a federal election year in Canada and the possibility that a different party from that which was governing at the time these proposals were introduced may form the next government. We have included discussion of these proposals below.*

BILL C-59 AND BILL C-69

On June 20, 2024, Bill C-59 and Bill C-69 received royal assent and enacted the legislation implementing the investment tax credit for carbon capture, utilization and storage ("CCUS ITC"), the clean technology investment tax credit ("CT ITC"), the CH ITC, the clean technology manufacturing investment tax credit ("CTM ITC") and the prevailing wage and apprenticeship requirements that a taxpayer must elect to satisfy in order to maximize the applicable rate for a CCUS ITC, CT ITC, CH ITC or CE ITC. The legislation enacted was in the same form as introduced on November 20, 2023. Refer to our National Tax Group's **2023 Year-In-Review** publication for a summary of the draft legislation.

ELECTRIC VEHICLE SUPPLY CHAIN INVESTMENT TAX CREDIT

To support investments in Canada's electric vehicle industry, Budget 2024 announced the EV ITC as a 10% investment tax credit in respect of the cost of buildings used in the three qualifying segments of the Canadian electric vehicle supply chain: (1) electric vehicle assembly; (2) electric vehicle battery production; and (3) cathode active material production.

The EV ITC would be available in respect of property that is acquired and becomes available for use on or after January 1, 2024. The Fall Economic Statement confirms that the EV ITC will be phased out with a reduced rate of 5% for property that becomes available for use in 2033 or 2034, and no credit available for property that becomes available for use after 2034.

The Fall Economic Statement included additional design and implementation details for the EV ITC and indicated that other design elements will generally be based on those of the CTM ITC under section 127.49.

Eligible Property

Property eligible for the EV ITC would include buildings and structures, including their component parts, described in paragraph (q) of capital cost allowance Class 1 in Schedule II to the Income Tax Regulations. Eligible property must be used in one of the three qualifying segments which the Fall Economic Statement defines as follows:

— electric vehicle assembly which comprises the final assembly of a fully electric vehicle or a plug-in hybrid vehicle with a battery capacity of at least 7kWh;

— electric vehicle battery production which comprises the manufacturing of battery cells or battery modules used in the powertrain of a fully electric vehicle or plug-in hybrid vehicle; and

— cathode active material production which includes the production of cathode active material used as an input to manufacture battery cells used in the powertrain of a fully electric or plug-in hybrid vehicle other than preliminary processing activities such as activities that could generally allow property to qualify for the CTM ITC.

Investment Requirement

As initially described in Budget 2024, to be eligible for the EV ITC, a corporation must have invested in, and claimed the CTM ITC in respect of, each of the three qualifying segments. The Fall Economic Statement provides that, in order to satisfy this requirement, a corporation or a related group of which the corporation is a part, must:

— acquire property eligible for the CTM ITC at a cost of at least $100 million and that has become available for use in each of the three segments; or

— acquire property eligible for the CTM ITC at a cost of at least $100 million and that has become available for use in two of the three segments and hold shares of an unrelated corporation, representing at least 10 per cent of the voting rights and 10 per cent of the value of the shares of that corporation, that acquires property eligible for the CTM ITC at a cost of at least $100 million in the other qualifying segment.

Recapture

EV ITC is proposed to be subject to repayment obligations similar to the existing recapture rules for the CTM ITC.

CLEAN ELECTRICITY INVESTMENT TAX CREDIT

Announced in Budget 2023, the CE ITC is a 15% refundable investment tax credit applicable to investments in "clean electricity property" (as defined in subsection 127.491(1)). The stated purpose of the CE ITC is "to encourage the investment of capital in the deployment of clean electricity property in Canada." The August 12

Proposals include draft legislation to implement the CE ITC. Budget 2024 indicated that the Government intended to table legislation enacting the CE ITC in the House of Commons in fall 2024. With that deadline now passed, the Fall Economic Statement provides that legislation enacting the CE ITC is expected to be introduced in the House of Commons "soon".

The CE ITC is available as of Budget Day 2024 in respect of projects that commenced construction on or after Budget Day 2023 and before January 1, 2034.

There is significant (although not perfect) overlap between the types of property that qualify for the CE ITC and the CT ITC. Notably, eligible for the CE ITC but not the CT ITC is "nuclear energy equipment", "qualified natural gas energy equipment", "qualified interprovincial transmission equipment", and hydro-electric property that exceeds the 50 megawatt-rated capacity limited in subparagraph (d)(ii) of Class 43.1.

The most significant difference between the CE ITC and the CT ITC is that the CE ITC is available to both taxable Canadian corporations and certain tax exempt entities. More specifically, the CE ITC is available to be claimed by designated provincial Crown corporations, corporations described in paragraph 149(1)(d.5) of which not less than 90% of the shares or capital are owned by one or more municipalities in Canada or "Aboriginal government" (as defined in subsection 241(10)) or similar Indigenous governing bodies described in paragraph 149(1)(c), corporations described in paragraph 149(1)(d.6) of which 100% of the shares (other than directors' qualifying shares) are owned by one or more municipalities in Canada or "Aboriginal government" (as defined in subsection 241(10)) or similar Indigenous governing bodies described in paragraph 149(1)(c), a corporation of which all of which 100% of the shares (except directors' qualifying shares) or capital of which is owned by any combination of the above entities.

Also eligible for the CE ITC is a pension investment corporation to which paragraph 149(1)(o.2) applies or a trust that, at all relevant times, each beneficiary of which is a pension investment corporation described in paragraph 149(1)(o.2), that is a limited partner of a partnership and the sole undertaking of which is the holding of its interest in the partnership.

The August 12 Proposals include draft legislation clarifying that, where a partnership acquires property eligible for both the CE ITC and the CT ITC, a partner will be able to claim its reasonable share of either credit for which the partner is otherwise eligible (but not both credits in respect of the same property). For example, if a partnership with a 50% tax-exempt corporation partner and a 50% taxable Canadian corporation partner incurs expenditures to acquire property that is eligible for both the CE ITC and the CT ITC (and the Labour Requirements are met), the tax-exempt corporation partner should be entitled to claim a credit equal to its reasonable share of the 15% CE ITC to which the partnership would be entitled if it were an eligible entity for purposes of the CE ITC and the taxable Canadian corporation should be entitled to claim a credit equal to its reasonable share of the 30% CT ITC to which the partnership would be entitled if it were a qualifying taxpayer for purposes of the CT ITC.

If a qualifying entity does not elect to satisfy the Labour Requirements, the amount of the CE ITC is reduced by 10%. 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.

CE ITC for Provincial and Territorial Governments

Budget 2023 included the following statement regarding the requirements that would need to be satisfied to access the credit:

> *In order to access the tax credit in each province and territory, other requirements will include a commitment by a competent authority that the federal funding will be used to lower electricity bills, and a commitment to achieve a net zero electricity sector by 2035.*

This statement introduced significant uncertainty as it was not, at that time, apparent that these conditions would only apply to provincial and territorial Crown corporations or what specifically would be required to satisfy the conditions.

Budget 2024 indicated that provincial and territorial Crown corporations would be eligible to claim the CE ITC only in respect of investments made in eligible property situated in designated jurisdictions. In the Fall Economic Statement, the Government details the proposed conditions that must be satisfied by provincial and territorial governments in order for the jurisdiction to be designated for purposes of Crown corporations claiming the CE ITC and reporting requirements for provincial and territorial Crown corporations claiming the CE ITC. For additional details regarding such proposed conditions and reporting requirements please refer to our **detailed review** of the Clean Economy Tax Credit measures announced in the Fall Economic Statement.

Expanded Eligibility of the CE ITC for the Canada Infrastructure Bank

The Fall Economic Statement proposes to expand eligibility for the CE ITC by including the Canada Infrastructure Bank as an eligible entity for purposes of the CE ITC.

Under the August 12 Proposals, for purposes of the CE ITC, the capital cost of a clean electricity property to a qualifying entity is reduced by the amount of any government assistance or non-government assistance received by the qualifying entity in, or before, the taxation year in which the property is acquired. The Fall Economic Statement proposes to introduce an exception so that financing provided by the Canada Infrastructure Bank would not reduce the capital cost of a clean electricity property to a qualifying entity for purposes of the CE ITC.

The Fall Economic Statement proposes that the measures with respect to the Canada Infrastructure Bank and the CE ITC would apply to clean electricity property that is acquired and becomes available for use on or after December 16, 2024.

SELECT PROPOSED AMENDMENTS TO CLEAN ECONOMY TAX CREDITS

Polymetallic Projects

Budget 2024 proposed to modify the CTM ITC to expand eligibility for the credit to businesses engaged in polymetallic projects. The August 12 Proposals include draft legislation effecting that proposal by modifying the "CTM use" definition in subsection 127.49(1) by replacing the "producing all or substantially all qualifying materials" requirement (generally regarded as 90% or more) with an "expected to produce primarily qualifying materials" test which will be measured in terms of the fair market value of all commercial outputs relevant to the taxpayer's CTM ITC. Budget 2024 indicated that the "primarily" test is generally regarded as 50% or more; however, the explanatory notes accompanying the August 12 Proposals do not comment on the meaning of the term "primarily."

To support a claim for the CTM ITC in respect of a polymetallic project, a taxpayer must submit to the Canada Revenue Agency, an attestation from an arm's-length qualified engineer or geoscientist for each relevant mine or well site. If a taxpayer does not submit such attestation, then its CTM ITC in respect of a polymetallic project is deemed to be nil.

Eligibility for Waste Biomass

The August 12 Proposals also include draft legislation reflecting the 2023 Fall Economic Statement proposals to expand the property eligible for the CT ITC to support the generation of electricity, heat, or both electricity and heat from waste biomass comprising "specified waste materials" as defined in subsection 1104(13) of the Regulations. Eligible systems under this expanded eligibility for the CT ITC must:

- use feedstock which derives all or substantially all of its energy content (expressed as the higher heating value of the feedstock) from specified waste materials, as determined on an annual basis;
- not use fuel that is not produced as an integrated part of the system (even if produced from specified waste material); and
- not exceed a heat rate threshold of 11,000 British thermal units per kilowatt-hour.

The August 12 Proposals also include the 2023 Fall Economic Statement proposal to amend subsection 1104(17) of the Regulations to clarify that properties that would otherwise be eligible for inclusion in Class 43.1 or 43.2 will only be deemed not to be eligible if there is substantial non-compliance by the taxpayer with environmental laws, bylaws and regulations at the time the property first becomes available for use.

Preliminary Work Activity

The August 12 Proposals introduce a new reduction to the capital cost of clean technology property for any amount that is in respect of an expenditure incurred for a preliminary work activity ("Preliminary Work Activity Reduction"). An equivalent adjustment to the capital cost of clean electricity property for the purpose of the definition of "clean electricity investment tax credit" in subsection 127.491(1) is also proposed.

The proposed preliminary work activity definition defines a preliminary work activity to mean any activity that is preliminary to the acquisition, construction, fabrication or installation by or on behalf of a taxpayer of property including, but not limited to, a preliminary activity that is any of the following:

- obtaining a right of access to a project site or obtaining permits or regulatory approvals (including conducting environmental assessments);
- performing front-end design or engineering work, including front-end engineering design studies or process engineering work for the project, including (i) collecting and analyzing of site data, (ii) calculating energy, mass, water or air balances, (iii) simulating and analyzing the performance and cost of process design options, (iv) selecting the optimum process design, and (v) conducting feasibility studies or pre-feasibility studies;
- clearing or excavating land;
- constructing a temporary access road to the project site; or
- drilling of a well.

Although an analog of the Preliminary Work Activity Reduction was proposed to apply to the CCUS ITC and the CH ITC since the original draft legislation for those credits was released by the Department of Finance, such a reduction to the capital cost of property eligible for the CT ITC and CE ITC was not proposed until the August 12 Proposals. Despite this, the Preliminary Work Activity Reduction definition is proposed to apply retroactively to the original effective date for both CT ITC and CE ITC. It should therefore be considered in determining the capital cost of clean technology property for any project in respect of which a CT ITC or CE ITC will be claimed regardless of the timing of the claim.

Expanded Eligibility of CH ITC for Methane Pyrolysis Projects

The CH ITC was enacted on June 20, 2024 when Bill C-69 received royal assent. The CH ITC is currently available in respect of hydrogen produced from electrolysis of water or from the reforming or partial oxidation of natural gas or other eligible hydrocarbons (where emissions are abated using a carbon capture, utilization and storage ("CCUS") process). The Fall Economic Statement proposed to expand the CH ITC to include methane pyrolysis as an eligible production pathway and the Government indicates that it will continue to review eligibility for other low-carbon hydrogen production pathways.

The CH ITC will only be available in respect of hydrogen produced from the pyrolysis of natural gas and other eligible hydrocarbons on or after December 16, 2024.

Eligible Methane Pyrolysis Projects

The Fall Economic Statement proposes to expand the eligibility for the CH ITC to include projects that produce hydrogen from the pyrolysis of natural gas and other eligible hydrocarbons. The existing legislation regarding the CH ITC will generally apply in respect of such projects subject to certain modification:

- a pyrolysis process is not required to capture carbon dioxide using a CCUS process; however, dual-use heat and power equipment must still capture carbon dioxide using a CCUS process;
- support for the capital costs of the pyrolysis reactor system is limited to $3,000 per tonne of annual hydrogen production capacity;
- the taxpayer will be required to track the end use of its solid carbon produced from a methane pyrolysis project through an end-use plan. Such plan must account for all solid carbon produced, and its end use, for a period of 7 years beginning from when the project first produces hydrogen (the "End-Use Plan Requirement");
- a taxpayer that undertakes a methane pyrolysis project will be required to establish solid carbon offtake contracts prior to the beginning of its compliance period for the CH ITC. Such contract must bind the purchaser to use the solid carbon as described in the end-use plan and include terms to facilitate information sharing to confirm the end-use of the solid carbon;
- methane pyrolysis projects will be restricted from venting or flaring hydrogen produced by the project with an exception for venting or flaring for system integrity and safety (the "Venting/Flaring Restriction").

The Fall Economic Statement indicates that additional details regarding the information that would be required to satisfy the End-Use Plan Requirement, and regarding how the Venting/Flaring Restriction will apply, will be provided at a later date.

Eligible Methane Pyrolysis Equipment

The Fall Economic Statement expands the property eligible for the CH ITC to, when part of an eligible pyrolysis process, include property that is used to produce all or substantially all hydrogen from methane pyrolysis, determined without reference to any solid carbon that is produced. Such eligible property will include pyrolysis reactors, heat exchangers, separation equipment and purifiers, and compression and on-site storage equipment. Downstream equipment will not be eligible including dryers, pulverisers, bag collectors, densifiers, and pin mixers.

Carbon Intensity

Methane pyrolysis will generally be required to follow existing rules for measuring carbon intensity of hydrogen produced and to be produced using the Fuel LCA Model. The Government intends to expand its Clean Hydrogen Investment Tax Credit – Carbon Intensity Modelling Guidance Document to include methane pyrolysis projects.

In addition to the existing rules with respect to measuring carbon intensity, the carbon intensity of a methane pyrolysis project will depend on the end-use of the solid carbon produced by the project:

- if the solid carbon is converted or incorporated into a product that is not intended for use as a fuel source by the taxpayer or a purchaser then the project will be able to allocate project emissions between the hydrogen and solid carbon co-product based on relative production adjusted for energy content;
- if the solid carbon is treated as waste and sent to a landfill, the project will not be permitted to allocate any carbon emissions to the solid carbon (i.e., all of the carbon intensity will be allocated to hydrogen production); or
- if the solid carbon is used for any other purpose, or the use of the solid carbon is not accounted for, then the project will be assumed to have disposed of it in a manner that results in converting the solid carbon to carbon dioxide that is released into the atmosphere and any carbon emission would be included in the calculation of the project's carbon intensity.

The end-use of a project's solid carbon, as described in the taxpayer's end-use plan (described above), will factor into the calculation of the project's "actual carbon intensity" and "expected carbon intensity" (each as defined in subsection 127.47(1)).

UPDATED TIMELINE FOR CLEAN ECONOMY TAX CREDIT LEGISLATION

The August 12 Proposals included draft legislation for the CE ITC, the proposed expansion of the CT ITC to support the generation of electricity and/or heat from waste biomass, and the proposed expansion of the CTM ITC to support certain polymetallic mining projects.

Since the 2023 Fall Economic Statement, the Government's timeline had indicated such legislation would be introduced in Parliament by Fall 2024. With that deadline passed, the Fall Economic Statement indicates that the Government will introduce legislation to enact the CE ITC and the expanded CT ITC, as well as publish draft legislation with respect to the EV ITC "soon".

CLEAN ECONOMY TAX CREDIT BRIDGE FINANCING

Liezl Behm and Josh Friedman

Concurrent with the rollout of the Clean Economy Tax Credits, the Canadian market is seeing considerable growth in the development of clean electricity projects that are eligible for the CCUS ITC, CT ITC, CH ITC, CTM ITC and the CE ITC ("ITCs"). The relatively predictable stream of ITC returns that a developer can expect to receive in respect of a project's eligible expenditures represents an additional capital source that can be modelled and financed. Developers can leverage ITC receivables to add ITC financing to the capital stack on clean energy projects and thus they offer an attractive source of project financing. Such ITC bridge financing is beginning to take shape as an available source of funding for clean energy projects across the country.

McCarthy Tétrault acted as lead counsel to the Sponsor group in the Higgins Mountain Wind Farm Project in Nova Scotia, a 2024 multi-bank financing transaction that was one of the first ITC bridge financings of a clean energy project in Canada. Since then, ITC bridge financing has grown dramatically in the Canadian clean energy space. A few notable features of ITC bridge financing structures that have begun to emerge are as follows:

— **Business Organization**: Generally, the ITCs are only available for qualifying taxpayers. For many of the ITCs, qualifying taxpayers are taxable Canadian corporations (see the summary above regarding the additional entities eligible for the CE ITC). However, the Clean Economy Tax Credit legislation includes rules that apply to partnerships, enabling partners that are taxable Canadian corporations to claim their reasonable share, limited to the partner's at-risk amount, of ITCs derived from qualified expenditures made by the partnership to acquire eligible property. Thus, borrowers under ITC bridge financing arrangements may either be in the form of a corporation or a limited partnership with corporate partners. To maximize the benefit of ITCs in a limited partnership structure, a number of complex tax considerations must be carefully managed.

— **Indigenous Ownership**: Similar to other projects with Indigenous participation, where limited partnership structures are used for ITC bridge financing and there is at least one Indigenous limited partner, the limited partnership interests of any Indigenous partner must be held by a corporate entity and not the Nation in its own capacity. This helps address lender concerns over taking a security interest in the limited partnership units and assists in mitigating tax implications that would jeopardize a project's eligibility for ITCs.

— **ITC Insurance**: Depending on the structure leveraged for the ITC bridge financing, lenders may require additional protections. One such protection includes the requirement of the borrower to obtain ITC insurance. The ITC insurance is structured to hedge against the risk of nonpayment, or lower than expected payment, of ITC receivables on account of certain insured events. Such insurance policies are available but are expensive, can be limited in scope and are often subject to robust negotiation with insurers.

— **Additional Protections**: In addition to ITC insurance, other protections lenders often seek in connection with ITC bridge financing include (i) the requirement to appoint an "ITC consultant" (who prepares an initial report outlining the eligible property) and operates similar to an independent engineer, (ii) the requirement for the independent engineer (or another advisor) to evaluate the ITC consultant's report on a draw by draw basis to certify the draws are for eligible property to the extent they are draws under the ITC bridge loan, (iii) the requirement to appoint an independent labour monitor (to the extent the borrower is looking to leverage the full 30% ITC receivables as part of the ITC bridge financing) and (iv) a professional opinion on the tax structuring (from an accounting firm or law firm).

Thus, while the Clean Economy Tax Credit regime is in its infancy and will likely be subject to further structural change as the market develops and the legislation is refined over time, legal and financial practitioners in the field are able to leverage early expertise to facilitate ITC bridge financings for clean energy developers.

POWERING DATA IN CANADIAN JURISDICTIONS

By Kimberly Howard, Stephen Furlan, Jacob Stone, Rachael Carlson and Riley Thackray

Powering Data in Canadian Jurisdictions

INTRODUCTION

The prevalence of cloud-based services, computer and mobile applications, artificial intelligence ("**AI**") and machine learning technology and other data-driven industries are driving exponential global demand for data storage infrastructure. In Canada, the data centre market has seen a steady increase in growth and is expected to reach a value of C$9.04 billion by 2029.[1]

What is a Data Centre?

At its most simple, a data centre is a physical facility with computing and storage resources used to house data and software applications. In the recent past, organizations would have physical servers on site to serve this function.

More recently, data centres have arisen as a centralized hub of networked computer servers used for remote storage, processing and distribution of substantial volumes of data. This data must be able to connect across multiple data centres.

Data centres consist of three key components: (a) network infrastructure; (b) storage infrastructure; and (c) computing resources.

Figure 1 – Rocky View (Beacon Data Centers)

While Canadian provinces seek to attract data centre-related investments, the drive for data centres in Canada provides a unique challenge from a power supply perspective. Put simply – data centres require a lot of energy. Power is used to both support the data storage and processing functions, but also

1 Encor Advisors, "The State of Data Centers in Canada" [2024], (October 25, 2024).

to cool the multitude of servers in these facilities. A burgeoning, energy-intensive industry seeking connection to provincial power grids in the midst of the green energy transition, unsurprisingly, results in practical, operational and regulatory complexity.

This article provides an overview of market trends in key Canadian jurisdictions for data centres and indicates the regulatory risk profile when seeking to power a data centre in these jurisdictions (whether through connecting to the grid or bringing your own generation, or "BYOG").

The Impact of AI on Data Centre Power Demands

While all data storage requires significant energy, a major driver in the increased energy demand is the proliferation of AI applications. For example, a ChatGPT query consumes 10 times the energy required to run a standard Google search. It is predicted that AI will drive a 160% increase in global data centre energy consumption by 2030.[2]

WHY CANADA?

Canada is currently home to more than 240 data centres, with the vast majority of such centres located in Ontario.[3] Numerous data centres are in the planning and regulatory approval stages.

Canada is an attractive jurisdiction for data centre investment for several key reasons. Canadian jurisdictions can provide low-cost electricity, reliable power infrastructure, renewable and clean energy resources (which may align with certain investors' sustainability initiatives), and cool climates, which reduce cooling costs.[4]

Further, Canada is particularly favourable for the storage of sensitive information, boasting a stable political environment and strict privacy and security laws which apply to personal information.

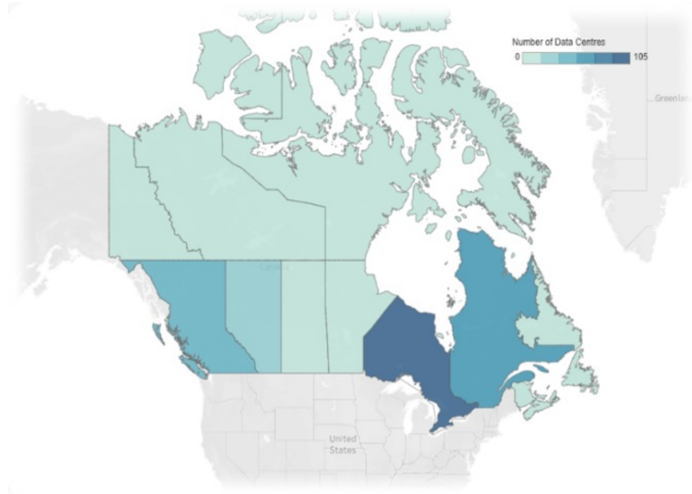


Figure 2 – Market Snapshot (Government of Canada)

Federal Funding for Data Centres – the AI Compute Challenge

The federal government is also investing in data centres to support Canada's AI advantage. On December 5, 2024, the Minister of Innovation, Science and Industry launched the Canadian Sovereign AI Compute Strategy, which seeks to provide access to cutting-edge AI infrastructure. Through this strategy, among other things, up to C$700 million will be invested to grow Canadian AI champions by leveraging investments in new or expanded data centers through the AI Compute Challenge. The AI Compute Challenge provides funding for, among other things, supporting establishment of AI data centres.[5]

2 Government of Canada, "Market Snapshot: Energy demand from data centers is steadily increasing, and AI development is a significant factor" (October 2, 2024).

3 See Data Center Map, "Canada Data Centers" (last visited 4 December 2024) online.

4 Government of Canada, "Market Snapshot: Energy demand from data centers is steadily increasing, and AI development is a significant factor" (October 2, 2024).

5 Government of Canada, "Canada to drive billions in investments to build domestic AI compute capacity at home" (December 5, 2024).

MARKET OVERVIEW – DEVELOPMENTS IN 2024 BY PROVINCE

Like any other area of investment, all jurisdictions are not made equally when it comes to data centre investments. The section below sets out the general posture of provincial governments to data centres as evidenced by announcement and developments over the past year.

British Columbia

Currently, there are more than 30 data centres in the Province of British Columbia ("BC"), run by industry leaders like Cologix, Cyxtera, eStruxture and Equinix.[6] The largest data centre in BC is an 80- megawatt ("MW") facility in Mackenzie, BC.

BC has not published a specific data centre strategy or given a clear signal to investors whether additional data centres are welcome in BC. BC has issued a complete ban on connecting crypto-mining projects to the grid (see right). In addition, BC has just completed a Call to Power (which is seeking to meet projected energy demands). Given this approach to crypto-mining and general demand constraints, coupled with the lack of clear investment signal from the province, it is difficult to ascertain BC's precise position towards large load connections to service data centres on a go-forward basis.

Unlike the province, BC Hydro, a provincial Crown corporation which is the main electricity distributor in BC, appears to be actively encouraging data centre connections. BC Hydro's stated position is that "data centers that establish operations in BC improve system reliability and redundancy by taking advantage of BC Hydro's integrated grid"[7] and have a "competitive advantage against other North American jurisdictions" due to BC's data sovereignty laws, access to fibre networks and subsea cables (as Google's Topaz subsea cable enhances data connectivity by providing a direct fibre link between Vancouver and Asia), clean hydroelectricity, access to water for cooling, and geopolitical security and reliability. Also, data centres may be eligible for certain tax credits or exemptions under provincial programs. Further, BC has among the lowest energy rates in North America, coupled with a stable and clean power supply. BC Hydro encourages project owners and proponents of data centres to reach out to BC Hydro to identify suitable industrial sites for their operations.[8] BC Hydro aims discuss eligibility for reduced rates for large electrical loads, connection study and project funding, fuel switching funding and stacking incentives.

Perhaps unsurprisingly in this context, industry announcements for investments in BC data centres over the past year have been few and far between, overshadowed by the significant activity in its neighbour to the east, Alberta.

It's a "No" for Now – Crypto-mining projects in BC

On May 7, 2024, BC enacted Bill 24, the Energy Statutes Amendment Act, 2024, which amended the Utilities Commission Act ("UCA") to enable the province to enact regulations regarding public utilities' provision of electricity service to cryptocurrency miners. This enactment followed a report from BC Hydro suggesting that crypto-mining could compromise BC's clean energy transition and a December 2022 direction from the province directing the British Columbia Utilities Commission ("BCUC") to effectively suspend new electricity connections for crypto-mining projects for 18 months (until June 2024).

In an unsuccessful court challenge to the 18-month suspension (Conifex Timber Inc. v. British Columbia (Lieutenant Governor in Council), 2024 BCSC 177), the Supreme Court of British Columbia held that differentiation based on economic or cost-of-service reasons, which can include unique electricity consumption characteristics, does not constitute undue discrimination and that the province's direction was consistent with the purposes of the UCA (which included regulation of public utilities so that the general public is well served by those utilities).

In June 2024, the 18-month suspension was extended to December 2025 via the Cryptocurrency Power Regulation, in order to allow additional time for policy development and engagement in respect of crypto-mining connections.

6 BC Hydro, "**Why is British Columbia a growing market for data centers?**" (last visited 8 December 2024) online: Electrifying Your Business.

7 See Data Centers: **Establishing Operations in BC** (last visited December 17, 2024).

8 BC Hydro, "**Why is British Columbia a growing market for data centers?**" (last visited 8 December 2024) online: Electrifying Your Business.

Alberta

On December 4, 2024, the Government of Alberta launched its "**Artificial Intelligence (AI) Data Centers Strategy**"[9] (the "Strategy") to attract C$100 billion in investments over five years and establish the province as a leader in AI-driven data centres. The Strategy incorporates three strategic pillars: scalable power generation, efficient cooling technologies, and competitive taxation. To support the strategic pillars, Alberta will harness its abundant natural resources and innovative energy infrastructure to support the development of high-capacity, reliable and affordable power solutions for AI data centres. Competitive tax rates, streamlined regulations and off-grid energy options aim to support scalable and cost-effective infrastructure.

This strategy follows significant indicators of desired investment in Alberta in recent years. Following investment of C$2.57 billion in Canada between 2016 and 2021, on December 20, 2023, Amazon Web Services ("AWS") Canada West launched its second data centre in Canada, known as Canada West (Calgary) Region.[10] This data centre is expected to create 1,000 jobs and add approximately C$4.9 billion to Canada's gross domestic product ("GDP") over the next 15 years.[11] Together with the first Canadian AWS Region, AWS Canada (Central), launched in 2016, AWS expects their planned investment will add C$43.02 billion to Canada's GDP and support more than 9,300 full-time equivalent jobs in the Canadian economy.[12]

Between April 8, 2024 and May 10, 2024, Beacon AI Data Centers, a private development firm, submitted five large AI hubs to the Alberta Electricity Service Operator's ("AESO") connection list, which would require between 200 MW and 400 MW of demand per facility.[13] On October 29, 2024, the largest Canadian-owned and operated data centre provider, eStruxture, **announced** that they plan to invest over C$750 million to construct CAL-3, a 90-MW data centre in Rocky View County, just north of Calgary.[14]

Lastly, in December 2024, O'Leary Ventures and the Municipal District of Greenview entered into a partnership to build the world's largest artificial data centre – named Wonder Valley – in the District of Greenview near Grande Prairie, Alberta. The data centre will be powered by off-grid natural gas and geothermal power. In respect of this initiative, Kevin O'Leary states, "[w]e will engineer and build a redundant power solution that meets the modern AI compute reliability standards. The first phase of 1.4 GW will be approximately US$ 2 billion with subsequent annual roll out of redundant power in 1 GW increments. The total investment over the lifetime of the project will be over [US]$70 billion when considering the infrastructure, power, data centers and ancillary structures."[15]

Figure 3 – **Wonder Valley (O'Leary Ventures)**.

Ontario

Ontario introduced its "**Building a Digital Ontario**" strategy in 2021, through which it sought to lay the foundation for Ontario to become "the world's leading digital jurisdiction." Ontario currently hosts the most data centres in Canada. Ontario has over 80 data centres, with the majority located in Toronto due to its dense network infrastructure. 16 new data centres are anticipated to become operational in Ontario by 2035.

9 Government of Alberta, "**Alberta's AI data center strategy: powering the future of artificial intelligence**" (4 December 2024) online (pdf).
10 Amazon Web Services, "**The AWS Canada West (Calgary) Region is now available**" (20 December 2023) online.
11 Amazon Web Services, "**AWS Announces Plans to Open Second Region in Canada**" (8 November 2021) online.
12 Amazon Web Services, "**The AWS Canada West (Calgary) Region is now available**" (20 December 2023) online.
13 See **July 2024 AESO Connection List**.
14 eStruxture Data Centers, "**eStruxture Announces Alberta's Largest Data Center: Introducing the Groundbreaking CAL-3 Facility**" (15 November 2024) online.
15 Cision, "**Kevin O'Leary in cooperation with the Municipal District of Greenview to develop the world's largest AI Data Center Industrial Park 'Wonder Valley' in the Greenview Industrial Gateway ("GIG") near Grande Prairie in North West Alberta, Canada**" (December 9, 2024).

In March 2024, the Ontario Independent Electricity System Operator ("IESO") **released** its Annual Planning Outlook for Ontario's electricity system needs for 2025–2050. In this report, data centre electricity demand growth is recognized as a contributor to additional expected power use in Ontario's commercial sector. Later in the year, on October 16, 2024, the Ontario IESO **announced** a new projection of a 75% increase in Ontario's electricity demand by 2050, rising from 151 terawatt hours ("TWh") in 2025 to 263 TWh, with data centres listed among the industrial activities driving the accelerated demand growth.[16] The IESO further noted that data centres represent 13% of new electricity demand and 4% of total anticipated Ontario demand in 2035.

Québec

Québec has been a coveted jurisdiction for data centres, with many projects active or announced in recent years. Québec's attractive electricity rates and favorable climate are significant factors for data center operators when considering location. The province's chilly winters offer natural cooling for servers, enabling energy savings of up to 25% during the colder months. This natural cooling advantage shifts the peak electricity consumption to summer, primarily due to air conditioning demands.

Despite certain restrictions on connecting projects over 5 MW to the grid, Hydro Québec **continues to** anticipate an increase of 4.1 TWh in data centre demand from 2023 to 2032 in its Electricity Supply Plan,[17] representing a 14% increase in Québec's electricity demand. Projects which successfully secured energy supplies prior to 2023 continue their development, and additional centres were in the works in 2024:

— In June 2024, Microsoft commenced construction on a new data centre in L'Ancienne-Lorette, a suburb west of Québec City.[18] The project is aiming for completion by early 2026.

— In November 2024, QScale, a company serving the high-density workload market, **announced** it had secured a syndicated C$320 million credit facility to support the phases 3 and 4 development of its QScale Q01 Campus in Lévis, Québec, which are planned to be finalized in 2026. Once completed, the Q01 Campus is expected to have 142MW of IT capacity.

REGULATORY ENVIRONMENT

While governments and investors may desire data centre investment, regulatory frameworks for power generation and connection may impede or facilitate creating a data centre. A data centre may be powered one of two ways: either the data centre is powered exclusively by the grid, or the data centre is powered, in whole or in part, by its own generation. Each provincial analysis below sets out the availability of each of these options for data centres, based on current regulatory frameworks.

British Columbia

Generally, in order to construct or operate a public utility plant or system in BC (or an extension of either), a proponent is required to obtain a certificate of public convenience or necessity from the BCUC.

A public utility is defined in the UCA and refers to those who own and/or operate equipment or facilities in BC that provide energy to or for the public or a corporation, for compensation. A person who is not already classified

16 Independent Electricity System Operator, "**Electricity Demand in Ontario to Grow by 75 per cent by 2050**" (16 October 2024) online: Corporate IESO.

17 **Electricity Supply Plan 2023–2032** (in French only) filed with the Régie de l'énergie, (November 1, 2022); Hydro-Québec, "**Growth in electricity demand expected to continue in Québec**" (3 November 2022) online.

18 Data Center Dynamics, "**Microsoft breaks ground on data center in Quebec City, Canada**" (12 September 2024) online.

does not include a person that (a) provides a service or commodity "only to the person or the person's employees or tenants"; and (b) is not resold to or used by others. Accordingly, behind the fence generation is excluded from the overarching regulation of utilities in BC.[19] There is also a general exemption from the ambit of the majority of the UCA for persons that, provided they are not otherwise a public utility, sell a power service to BC Hydro, which means that a data center proponent could produce its own energy and sell excess generation to BC Hydro without regulation under the UCA.

Note, however, that there is ongoing **litigation** regarding whether the provision of electricity between affiliates is excluded from the definition of public utility. Accordingly, if selling electricity between affiliates (even behind the fence) it is unclear whether the operations would be subject to the UCA. Further, notwithstanding exclusion under the UCA, power plant proponents will be subject to regulation under a variety of other regulatory regimes in BC (i.e., environmental and municipal, for example).

The UCA provides the legislative basis for the BCUC oversight of the safety of public utilities in BC. Public utilities are required to provide and maintain their property and equipment in a manner that the BCUC considers in all respects adequate, safe, efficient, just, and reasonable. Under the UCA, a public utility is required to supply service to premises located within 200 metres of its supply line, unless the BCUC relieves the public utility of this requirement after a hearing and for proper cause. The BCUC may order a public utility to provide service to an applicant if a supply line is more than 200 metres from the applicant's premises (including making extensions necessary to provide that service).[20] Further, on reasonable notice, a public utility must provide suitable service without undue discrimination or delay to all persons that apply for service, are reasonably entitled to it, and pay or agree to pay the rates under the UCA.[21] While generally an applicant is able to receive service, it is important to note that they are only entitled to be serviced where reasonably entitled to such service, and require an order from the BCUC for an extension of service if not within 200 metres of an existing supply line. The BCUC is tasked with the general supervision of public utilities "so that the general public is well served by those utilities," so any decision-making in respect of a connection request will be made with that in mind.[22] Further, **Order in Council No. 692** and **BCUC Order G-390-22A**, which relieved BC Hydro from supplying service to cryptocurrency mining projects for 18 months, may foreshadow limitations on servicing other load-intensive projects.[23]

Alberta

Data centre operators seeking to connect to Alberta's energy grid require a connection order under the *Hydro and Electric Energy Act* ("HEEA"),[24] and must submit a system access service request to the AESO. The AESO will assess requirements for, and design, any transmission infrastructure needed to support the connection. AESO is only required to provide "reasonable opportunity"[25] for data centres to connect and is not required to provide connection within a specific time. The AESO is also required to ensure that safe, reliable and economic operation of the interconnected electric system, and will consider this duty when approaching any new connection

19 FortisBC and BC Hydro, the largest public utilities in BC, have net metering programs for renewable energy, which allow consumers to produce their own electricity. However, these programs are limited to a maximum nameplate capacity of 100 kw.

20 **UCA, s 29** The BCUC may also, following a hearing:

(a) order a public utility to extend its existing services in the general area the public utility may properly be considered responsible for developing, is feasible and required in the public interest, where the construction and maintenance of the extension will not necessitate a substantial increase in rates chargeable, or a decrease in services provided, by the public utility elsewhere (**UCA, s 30**); or

(b) order a public utility to extend its service to the extent the BCUC finds reasonable and proper, where the BCUC has concluded that an extension by a public utility of its existing service would provide sufficient business to justify the construction and maintenance of the extension, and the financial condition of the public utility reasonably warrants the capital expenditure required (**UCA, s 35**).

21 **UCA, s 39**. Recently, the BC Supreme Court has described the purpose of Section 38 in ***Conifex Timber Inc. v British Columbia (Lieutenant Governor in Council), 2024 BCSC 177*** [*Conifex*]:

> [21] Sections 38 and 39 are a partial codification of what is known as the "regulatory compact" between consumer and a public utility. That compact ensures that all customers have access to the utility at a fair price. The utility company, which is granted exclusive rights to sell its service in a particular territory, assumes a duty to adequately and reliably serve all customers in that area, and is required to have its rates and other operations regulated: *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board),* 2006 SCC 4 at para. 63.
>
> [22] The regulatory compact has also been held to encompass the duty of the public utility "to supply its product to all who seek it for a reasonable price and without unreasonable discrimination between those who are similarly situated or who fall into one class of consumers": *Chastain et al. v. British Columbia Hydro and Power Authority,* 1972 CanLII 985 (B.C.S.C.), 32 D.L.R. (3d) 443, at 454.

22 *Conifex* at para 48.

23 In *Conifex,* Conifex Timber Inc. was unsuccessful in arguing that the order directing the BCUC relieve BC Hydro from providing service to cryptocurrency mining projects was impermissible because it purported to direct the BCUC to exercise a power the BCUC did not possess (i.e., authorizing discrimination between customers on the basis of the intended use of electricity). Among other reasons, the court held that there was a "cost of service" justification for the order which was permissible.

24 **RSA 2000, c H-16**.

25 *Electric Utilities Act* ("EUA"), **SA 2003, c E-5.1**, s 16(1).

request.[26] Accordingly, where a connection request may result in transmission constraints or other issues, the ability to obtain a connection, or to obtain a connection promptly, is subject to the AESO's statutory discretion.

In Alberta, behind the fence generation is permissible through a number of mechanisms.[27] In fact, Alberta Technology Minister Nate Glubish has stated: "…if you want the fastest approval times and the most certainty and control over your project, go off-grid, go behind the fence and bring your own power."[28] For data centre proponents, the new exemption from the *Electric Utilities Act* under Section 2(1)(b) is available, which allows for self-supply generation produced on a property of which the generator is the owner or tenant and that is consumed solely on the property by such owner or tenant. Like the other jurisdictions noted in this article, exemption from generation specific legislation does not exempt the proponent from the application of municipal, environmental and other legislation.

Ontario

When seeking a connection to Ontario's power grid, data centre proponents will need to satisfy: (1) the IESO system impact assessment; (2) the transmitter's customer impact assessment; and (3) the Ontario Energy Board ("OEB") facility approval.

In the system impact assessment, the IESO will consider whether a proposed load connection will have a material adverse impact on the reliability of the integrated power system (considering the impact of the proposed load on the loading of transmission facilities, system voltages, voltage stability, load security and restoration, and ensuring reliability standards and other market criteria are met). Based on this criteria, the IESO may provide a notification or disapproval or a notification of conditional approval (which conditions may include, for example, the requirement to install remedial action scheme facilities). A recent system impact assessment report for a data centre load may be found here.[29]

At a basic level, transmitters are required under the **Transmission System Code** to ensure that new connections do not materially reduce the reliability or performance of the transmission system. The transmitter's customer impact assessment involves assessing the impact of proposed connections on existing customers, including project impacts on short circuits, voltage performance, supply reliability and supply capacity.

An OEB facility approval under the ***Ontario Energy Board Act*** is required to construct, expand or reinforce an electricity transmission line or an electricity distribution line or make an interconnection. When considering whether to provide such an approval, the OEB will consider whether doing so is in the public interest, with reference to the interests of consumers with respect to prices and the reliability and quality of electricity service.[30]

Where a data centre is seeking connection to the Ontario grid, and the particular load could compromise service to other Ontario customers, the connection may be refused or granted with conditions. To mitigate this risk, a data centre proponent may wish to produce its own generation rather than being serviced by the grid. Whether the data centre proponent proposes to have the data centre and generation facility owned by the same entity will have considerable implications on the regulatory path for self-generation. In order to generate electricity in Ontario for sale to another person, an electricity generation licence

26 **EUA, s 29**.
27 These exemptions include through designation as an "industrial system," through the statutory exemptions under **Section 2** of the EUA and micro-generation.
28 Calgary Herald, "**Varcoe: TransAlta eyes data center potential, prepares Alberta sites to be 'turnkey ready'**" (6 November 2024) online.
29 Final Report for GBE TOR1: Data Center, CAA ID: 2024-795 **Application Status**.
30 For example, see HydroOne, **Transmission Connection Procedures**, November 18, 2015, online.

is required,[31] and the sale of this electricity implicates a number of other licensing requirements.[32] On the other hand, producing electricity solely for one's own use is not subject to these same requirements.[33] In either case, power generation projects in Ontario are subject to other environmental and regulatory requirements which require careful consideration when designing an off-grid approach.

Québec

In response to evolving energy demands, the Government of Québec, alongside Hydro-Québec, is now empowered with approving high consumption projects of 5 MW and above, a shift from the previous threshold which allowed for projects under 50 MW to be automatically connected to the grid. Both new projects and existing projects slated for expansion are subject to this authorization process, which has been refined following the adoption of the **Bill 2**[34] in 2023. This revised electricity allocation process, which is initiated upon a request by the project developer to Hydro-Québec, is a result of the government's inability to fulfill all connection requests for electricity in the province.

Projects under consideration are assessed against a set of specific criteria, including their technical feasibility for connection, the overall effect on Québec's power grid, potential economic and regional development benefits, environmental and social impacts, and their consistency with established governmental directions. This approach is part of the government's ongoing commitment to strategic project analysis, and Hydro-Québec's commitment to facilitating an energy-efficient, economically dynamic and environmentally friendly future for Québec. You can find the list of the most recent grant of supply blocks of 5 MW and over **here**.

Conclusion

There is a growing demand for data centres in Canada, driven by advancements in AI and cloud-based services. Navigating the significant energy requirements of data centres, along with understanding the various provincial regulatory regimes and federal strategies, creates opportunities and challenges within each jurisdiction.

31 *Ontario Energy Board Act*, 1998, **SO 1998, c 15, Sch B**, s. 57(c).
32 For example, electricity wholesaler licences and electricity retailer licences.
33 Through the *Net Metering Regulation*, it is also possible to generate renewable electricity for one's own use while sending excess power to the grid, offsetting future electricity consumption.
34 *Act mainly to cap the indexation rate for Hydro-Québec domestic distribution rate prices and to further regulate the obligation to distribute electricity*.

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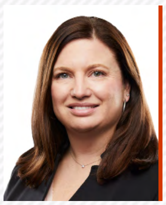

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