THE PUSH FOR ELECTRIFICATION AND A NET-ZERO GRID: DEVELOPMENTS, REACTIONS, AND IMPLICATIONS

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Canada's Draft Clean Electricity Regulations are poised to play a key role in achieving the federal government's goal of achieving net-zero carbon emissions by 2050. If implemented in their current state, the Draft Clean Electricity Regulations will place significant restrictions on electricity generation that is not low or non-emitting — restrictions which sometimes conflict with the interests and priorities of provincial governments. This article surveys the policy and legislative trends which have arisen across Canada from this federal-provincial dynamic — including concerns over electricity resource adequacy, climate goals, and grid stability. Pursuing aggressive electrification will require major shifts from the status quo, but law and policy should seek to balance the priorities of different jurisdictions rather than imposing a singular one-size-fits-all approach.

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I. INTRODUCTION

To achieve its goal of net-zero carbon emissions by 2050,[1] the federal government announced in August 2023 that a critical component of its energy transition plan is the development of additional low or non-emitting electricity generation.[2] To mandate this development, on 10 August 2023, the federal government proposed and published draft *Clean Electricity Regulations*,[3] under the *Canadian Environmental Protection Act, 1999*.[4] If adopted as drafted, commencing 1 January 2035, the *Draft CERs* would introduce significant restrictions on electricity generation that is not low or non-emitting, subject to limited exemptions.

On 31 August 2023, the federal government indicated that the *Draft CERs* underpin its plan to achieve a net-zero economy by 2050, stating that "Canada's electricity systems will be the backbone of Canada's net-zero economy," and that "[b]y fully decarbonizing our electricity grids by 2035, we are enabling the rest of the economy to electrify by 2050."[5] To achieve this shift, the federal government also introduced measures targeted at other sectors, such as the transportation sector, mandating accelerated emission reductions in parallel with requirements to electrify.[6]

The federal government's energy transition plan comes at a time when Canadian jurisdictions from coast-to-coast-to-coast are planning for aggressive growth of their electricity supplies to meet increased electrification demands and provincial clean energy goals, all the while experiencing transitional impacts arising from changes in generation fleets. The *Draft CERs*' proposal to directly regulate the generation of electricity has raised the ire of several provincial governments and sharpened the division between competing federal and provincial interests and policies on the necessary pace and technological direction of the transition to low or non-emitting electricity generation.

This article provides an overview of some of the policy and legislative trends across Canada that have arisen from this dynamic up to June 2024 — including responses to ensure electricity resource adequacy, regulatory response to climate goals, managing electricity and grid access as a scarce resource, tensions regarding imports and exports of electricity, and measures addressing affordability and consumer choice.

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1 *Canadian Net-Zero Emissions Accountability Act*, SC 2021, c 22 (became law in June 2021; sets out Canada's commitment to achieve net-zero emissions by 2050 in legislation).

2 Canada Energy Regulator, "Towards Net-Zero: Electricity Scenarios," online: [perma.cc/JWP3-4CHC].

3 Proposed Regulatory Text, (2023) C Gaz I, 2822 (*Clean Electricity Regulations*) [*Draft CERs*].

4 SC 1999, c 33 [*CEPA*].

5 Natural Resources Canada, *Powering Canada Forward: Building a Clean, Affordable and Reliable Electricity System for Every Region of Canada*, Catalogue No M4-241/2023E-PDF (Ottawa: NRC, 2023) [NRC, *Powering Canada Forward*] at 2.

6 See e.g. *Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations*, SOR/2010-201.

II. THE CLEAN ELECTRICITY REGULATIONS

Each provincial government has constitutional jurisdiction over electricity generation in their respective province.[7] Consequently, there is a lack of uniformity of electricity market structures and regulatory structures across Canada, which range from vertically integrated utilities in which a single entity holds a monopoly over generation, transmission, and distribution, to a fully deregulated generation sector with an open wholesale and retail market.[8] Vertically integrated utilities are common, and the monopoly utility is a Crown corporation in several provinces,[9] a single investor-owned utility in others,[10] or a combination of the two.[11] Ontario has a hybrid electricity market in which the provincial Crown corporation, the Ontario Power Generation, is responsible for more than half the electricity generation in Ontario, and additional generation is sourced through procurement contracts and a competitive wholesale market.[12] In contrast to the rest of Canada, Alberta has a fully deregulated competitive electricity market in which electricity is generated by a variety of independent power producers and regulated investors, or municipally owned transmission and distribution utilities.[13]

The generation supply mix in each provincial electricity market also varies significantly from province to province based on the availability of natural resources and technology. In Alberta, Nova Scotia, and Saskatchewan, more than 50 percent of electricity is generated from high greenhouse gas (GHG) emitting sources, such as natural gas and coal.[14] In contrast, electricity in British Columbia, Ontario, Manitoba, New Brunswick, Newfoundland and Labrador, Prince Edward Island, and Quebec is primarily generated

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7 *Constitution Act, 1867* (UK), 30 & 31 Vict, c 3, s 92A(c), reprinted in RSC 1985, Appendix II, No 5 [*Constitution Act, 1867*].

8 NRC, *Powering Canada Forward*, *supra* note 5.

9 British Columbia (BC Hydro), Saskatchewan (SaskPower), Manitoba (Manitoba Hydro), Quebec (Hydro-Quebec), and New Brunswick (NB Power).

10 Nova Scotia (Nova Scotia Power Inc.) and Prince Edward Island (Maritime Electric).

11 In Newfoundland and Labrador, generation and distribution of electricity is provided by two utilities. Newfoundland Power is an investor-owned utility, while Newfoundland & Labrador Hydro is a provincial Crown corporation: Canada Energy Regulator, "Provincial and Territorial Energy Profiles: Newfoundland and Labrador," online: [perma.cc/6FVD-9EB3].

12 Canada Energy Regulator, "Provincial and Territorial Energy Profiles: Ontario," online: [perma.cc/Y64V-JT8F].

13 Canada Energy Regulator, "Provincial and Territorial Energy Profiles: Alberta," online: [perma.cc/XQ2T-XLXB].

14 In 2023, Alberta generated 57 percent of its electricity was from natural gas: Alberta Electric System Operator, *AESO 2023: Annual Market Statistics* (Calgary: AESO, March 2024) at 13, online (pdf): [perma.cc/MUJ9-N9RP]. In 2023, Nova Scotia generated 31 percent of its electricity from coal and 17 percent from natural gas (Nova Scotia Power, "Powering a Green Nova Scotia, Together: Our Energy Stats," online: [perma.cc/AHN2-GHL4]). As of 4 November 2024, Saskatchewan generated 49 percent of its electricity from natural gas and 21 percent from coal (SaskPower, "Where Your Power Comes From," online: [perma.cc/SA6L-W76D]).

from low GHG emitting sources, such as nuclear and hydro.[15] Given the different energy markets and generation supply mix in each province, a one-size-fits-all approach to developing a net-zero grid poses multifaceted challenges in Canada.

Against this backdrop of provincially unique and diverse legacy electricity grid and generation profiles across Canada, the federal government introduced the *Draft CERs* to mandate the development of additional low or non-emitting electricity generation as a critical component of its energy transition plan. On 10 August 2023, in furtherance of its goal of economy wide net-zero emissions by 2050, the federal government released the *Draft CERs* for public comment.[16] Subject to limited exemptions, the *Draft CERs* would prohibit new electricity generation that is not low or non-emitting commencing in 2035 in an effort to ultimately eliminate emitting sources of supply connected to public electricity grids in Canada.[17] According to the federal government, carbon pricing alone is insufficient to achieve the required emissions reduction from the electricity sector, which accounted for 9.2 percent of total GHG emissions in Canada in 2020.[18]

The *Draft CERs* were accompanied by a Regulatory Impact Analysis Statement (RIAS) detailing the anticipated impacts and costs of implementing the *Draft CERs*. RIAS highlighted that the *Draft CERs* would disproportionately impact certain provincial electricity systems, creating cost savings for some, and imposing substantial costs on others.[19]

After receiving over 18,000 letters and emails in response to the *Draft CERs*, on 16 February 2024, the federal government released a public update (the Update).[20] The Update acknowledged that many of the submissions argued that the *Draft CERs* needed to provide more flexibility.[21] However, instead of proposing specific amendments to the *Draft CERs*,

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15 In British Columbia, as of July 2024, more than 90 percent of its generation is from hydroelectric sources: BC Hydro, "Generation System," online: [perma.cc/SZ7M-Q5G8]. In Ontario, as of 20 June 2024, 58 percent of energy production came from nuclear and 24 percent from hydro (Independent Electricity System Operator, "Electricity Facts," online: [perma.cc/37YY-3CWY]). Manitoba Hydro reported in 2023 that 97 percent of all electricity generated in Manitoba was from hydro sources (Manitoba Hydro, *2023 Integrated Resource Plan* (Winnipeg: Manitoba Hydro, July 2023) at 36). In 2023, New Brunswick reported that 19 percent of its electricity generation came from nuclear sources, 22 percent from renewables, 24 percent from fossil fuels, and 35 percent from imports (Government of New Brunswick, *Powering our Economy and the World with Clean Energy: Our Path Forward to 2035* (Fredericton: Government of New Brunswick, 2023) at 13). In 2022, Newfoundland and Labrador generated 97 percent of its electricity from hydro (Government of Canada, "Newfoundland and Labrador: Clean Electricity Snapshot," online: [perma.cc/B9Y7-5G9V]). In 2022, nearly 100 percent of Prince Edward Island's energy production was from wind, tidal, and solar sources (Government of Canada, "Prince Edward Island: Clean Electricity Snapshot," online: [perma.cc/X8SK-787G]). In Quebec, as of 6 November 2024, 100 percent of generation is from renewable sources, with 87 percent from hydro, 10 percent from wind, and the rest from solar or other renewables (Hydro-Québec, "Québec Hydropower: Clean, Renewable and Low in GHG Emissions," online: [perma.cc/WP3S-LGQM]).

16 Environment and Climate Change Canada, News Release, "Canada Powers Toward More Clean, Affordable, and Reliable Electricity with Draft Regulations" (August 10, 2023), online: [perma.cc/3P6C-8U4W].

17 *Draft CERs*, *supra* note 3, s 6.

18 Regulatory Impact Analysis Statement, (2023) C Gaz I, 2709 (*Clean Electricity Regulations*) [RIAS].

19 *Ibid* at 2781–83.

20 Environment and Climate Change Canada, *Clean Electricity Regulations Public Update: 'What We Heard' During Consultations and Directions Being Considered for the Final Regulations* (Gatineau: ECCC, 2024) at 4 [ECCC, "Update"].

21 *Ibid* at 4.

the Update outlined conceptual changes being *considered* by the federal government, adding further uncertainty regarding the potential impacts of the *Draft CERs*. The Update indicated the federal government's intention to publish the final *Clean Electricity Regulations* in late 2024.[22]

A. REGULATED GENERATOR EMISSION PROHIBITION

The *Draft CERs* are proposed to apply to electricity generating units that on or after 1 January 2025:

- Have a generating capacity of 25 megawatts (MW) or more;[23]
- "[G]enerates electricity using fossil fuel";[24] and
- "Are connected to an electricity system that is subject to [North American Electric Reliability Corporation] standards," which includes systems in Alberta, British Columbia, Manitoba, New Brunswick, Nova Scotia, Ontario, Quebec, and Saskatchewan.[25]

The rationale provided for the 25 MW threshold is to avoid regulating "units that are not expected to be a major source of GHG emissions" and "are too inefficient to be a viable option for broad deployment of baseload power."[26] The North American Electric Reliability Corporation connection requirement is intended to avoid regulation of own-use generation and generation supplying northern and remote locations with few options for electricity generation.[27]

The *Draft CERs* would essentially prohibit regulated generating units from emitting more than 30 tonnes of carbon dioxide (CO_2) per gigawatt hour (30t/GWh) of electricity generated on average in a calendar year (the Emission Prohibition), commencing on 1 January 2035.[28] The 30t/GWh value is ostensibly designed to align with the emissions intensity of natural gas generation with carbon capture and storage (CCS) achieving a 95 percent capture rate.[29]

To demonstrate compliance with the Emission Prohibition, the *Draft CERs* require the emissions intensity of a unit to be determined by dividing the quantity of CO_2 emissions

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22 *Ibid* at 9.
23 *Draft CERs*, *supra* note 3 at 2826.
24 *Ibid*.
25 *Ibid*. The North American Electric Reliability Corporation (NERC) is a non-profit international regulator that monitors the grid across the United States, Canada, and northern Mexico. NERC develops and enforces reliability standards to ensure the reliability and security of the grid. NERC and the regional entities (such as the Western Electricity Coordinating Council, Midwest Reliability Organization, and Northeast Power Coordinating Council) operate pursuant to joint agreements with the governments of Canada and Mexico. These entities operate either through the provincial regulatory framework or through Memoranda of Understanding with each Canadian province. See e.g. North American Electric Reliability Corporation, "About NERC," online: [perma.cc/B5A3-ZJJL].
26 RIAS, *supra* note 18 at 2816.
27 *Ibid*.
28 *Draft CERs*, *supra* note 3 at 2828–29 (proposed subsections 6(1) and 6(4)).
29 RIAS, *supra* note 18 at 2817.

attributed to a unit, in tonnes, by the quantity of electricity generated by the unit, in gigawatt hours (GWh), during a calendar year.[30] A unit's total CO_2 emissions are calculated based on the quantity of CO_2 emitted (including CO_2 emitted from the production of hydrogen fuel or steam used to produce electricity), less emissions attributed to the production of useful thermal energy, captured by CCS, or emitted during a declared emergency.[31]

Including emissions from hydrogen or steam used to generate electricity is intended to ensure that all emissions associated with electricity generated by a unit are included in the calculation of the unit's emissions intensity, regardless of the location of the supplier of the hydrogen fuel or thermal energy used in that unit for electricity generation.[32] For emissions captured by a CCS system to be excluded from a generating unit's total emissions for the purposes of the Emission Prohibition, the *Draft CERs* require the CO_2 to be permanently stored in a prescribed type of geological site, which includes either a deep saline aquifer used exclusively for CO_2 storage or a depleted oil reservoir for the purpose of enhanced oil recovery.[33] However, the *Draft CERs* also provide a transition period for regulated units that include a CCS system, acknowledging that some flexibility is needed for CCS technology to ultimately meet the ambitious 95 percent carbon capture rate.[34] Until 31 December 2039, these units may emit a calendar year average of 40 tonnes of CO_2 emissions per GWh of electricity generated.[35]

The 1 January 2035 date for compliance with the Emission Prohibition applies to units that combust coal, units commissioned after 1 January 2025, and units that increase their capacity by 10 percent or more after 1 January 2025.[36] For all other units, the Emissions Prohibition applies on the first of January of the year following the unit's *end of prescribed*

30 *Draft CERs*, *supra* note 3 at 2829–30 (proposed subsection 7(1)).

31 The formula used to calculate the emissions under the *Draft CERs*, *supra* note 3 at 2828–31, 2842–43 (proposed sections 6–8, 18) is: "$E_u – E_{th} – E_{ccs} + E_{ext} – E_{ec}$," Where "$E_u$" is a unit's CO_2 emissions from the combustion of fossil fuels; "E_{css}" is the quantity of CO_2 emissions captured and stored from a unit by a CCS system; "E_{ext} is the quantity of CO_2 emitted from the production of hydrogen fuel or the purchased or transferred steam used by the unit to generate electricity"; and "E_{ec}" is a unit's CO_2 emissions "during any period … for which the Minister has issued an [emergency circumstance] exemption."

32 RIAS, *supra* note 18 at 2727.

33 *Draft CERs*, *supra* note 3 at 2830–31, 2841 (proposed sections 8(1), 8(4), and 16).

34 RIAS, *supra* note 18 at 2817.

35 Provided that the unit's CCS system began operating "within the last seven calendar years," and "the unit [has] operated at or below 30 tonnes of CO_2 emissions/GWh for two periods of at least 12 continuous hours, with at least four months between those two periods, in [that] calendar year": *Draft CERs*, *supra* note 3 at 2828 (proposed section 6(2)).

36 Note that for boiler units converted from coal to natural gas, the Emission Prohibition under the *Draft CERs* applies on the latter of 1 January 2035 or the first of January of the calendar year that the emissions limits under the *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity*, SOR/2018-261 [*Regulations Limiting CO_2*] begin to apply to that unit. These are units that are considered "significantly boiler modified units" under that regulation, which provides that the emissions intensity limit under that regulation apply at the latest (depending on the units' achieved emissions intensity) in the eleventh year after the unit's end of useful life (*Regulations Limiting CO_2*, *ibid*, ss 3(4), 4(2)). The end of useful life of such units is established by the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulation*, SOR/2012-167, s 2(1), which establishes the "useful life" of such units to be at the latest 31 December 2019. Therefore, the Emission Prohibition applies to boiler units converted from coal to natural gas starting in 2040 at the latest.

life (the latter of the thirty-first of December of the calendar year 20 years after the commissioning date and 31 December 2034).[37]

However, generating assets can have varying expected useful lifespans, with many thermal generating technologies expected to last 45 years.[38] During consultations, various utilities, generation owners, and electric system operators raised the concerns that the truncated 20 year prescribed life gave rise to a profound risk of stranded assets and a disincentive to invest in new generation infrastructure, as the prescribed terms would not be sufficient to recoup investment costs and would create reliability risks.[39]

For Alberta, the RIAS models that comply with the *Draft CERs* would come from significant new investment in CCS.[40] If investments in CCS are not economical or technically feasible, the *Draft CERs*' truncated lifespan for generating units can be expected to result in a risk of significant stranded costs, limiting the ability of utility generators to optimize such sources of generation over the coming decades of energy transition planning horizons. Furthermore, multiple submissions in the *Draft CERs* consultation identified that the 30t/GWh performance standard (equivalent to a 95 percent capture rate), even with the transition period, is extremely stringent. For example, SaskPower's submission stated that the standard cannot be met by any current thermal generating unit and has not been met on an annual basis by any thermal unit fitted with CCS at the utility scale, calling the standard "theoretical and not yet commercially proven."[41] Given the stringency of the standard, multiple commentators expressed concern that the standard is achievable only under ideal conditions, which would serve as a deterrent to investment in CCS as a compliance mechanism.[42]

In response to the consultation, the Update reported that the federal government is *considering* several changes to the *Draft CERs*: (1) altering the 25 MW threshold; (2) replacing the Emissions Prohibition; and (3) extending the end-of-prescribed life.

1. THE 25 MW THRESHOLD

The Update noted feedback that the proposed minimum capacity threshold of 25 MW for a unit to be required to comply with the *Draft CERs* could create an incentive to commission new facilities with multiple units smaller than 25 MW.[43] In response, the Update stated that the federal government is considering making all new units at the same facility whose capacities collectively amount to 25 MW or greater, as well as single units

37 *Draft CERs*, *supra* note 3 at 2829 (proposed sections 6(4)(c), 6(5)).
38 RIAS, *supra* note 18 at 2721.
39 Government of Canada, "Canada Gazette, Part 1, Volume 157, Number 33: Clean Electricity Regulations: General Comment" (19 August 2023), online: [perma.cc/EG4W-H8U9] [Government of Canada, "*Draft CERs* General Comment Section"].
40 RIAS, *supra* note 18 at 2767.
41 SaskPower, "SaskPower Response: Federal Clean Electricity Regulations, Canada Gazette, Part I" (21 November 2023) at 10, online (pdf): [perma.cc/M3JS-NVFF] [SaskPower, "Response Appendix"].
42 Government of Canada, "*Draft CERs* General Comment Section," *supra* note 39.
43 ECCC, "Update," *supra* note 20 at 6.

25 MW or greater, subject to the *Draft CERs*.[44] However, the Update lacks clarity regarding how a "facility" would be defined in the regulation.

2. EMISSIONS PROHIBITION

In addition to the concerns noted above, the Update noted that many provinces and utilities commented that the Emissions Prohibition would be difficult to achieve for "load following"[45] natural gas fired units equipped with CCS because when "load following," a unit is likely operating at a higher emissions intensity (ramping up and ramping down to meet demand) than if the same unit were operated at a continuous steady-state.[46] In response, the principal change to the *Draft CERs* being considered is the replacement of the 30t/GWh Emissions Prohibition with a capacity-based, unit-specific annual emissions limit (in tonnes per year) linked to an adjusted emissions performance standard as follows:[47]

$$\underset{(t/year)}{\text{Unit Emission limit}} = \underset{(t/GWh)}{\text{Performance standard}} \times \underset{(capacity\ of\ unit)}{MW} \times \underset{(total\ hours\ in\ a\ year)}{8760\ hours} \times \underset{(unit\ conversion)}{\left(\frac{1\ GW}{1000\ MW}\right)}$$

The Update did not specify the applicable performance standard, indicating that it is to be determined, and noting that it is being considered to increase above 30 t/GWh.[48] Unlike the Emissions Prohibition, the annual emissions limit being considered would permit units unable to achieve the emissions performance standard to continue to be operated. However, the hours such units operate would be limited compared to the hours more emissions efficient units are able to operate, since such units would reach their annual emissions limit after fewer hours of operation. The Update also indicates that allowing an owner of multiple units operating in the same jurisdiction to pool the annual emissions limits of such units is under consideration, which would enable the operation of more efficient units above each individual unit's limit, offset by fewer hours of operation of less efficient units.[49]

The Update opined that the potential to pool emissions limits, the use of offsets as a compliance option (discussed below), and the annual emissions limit approach would enable the owner of a generating unit subject to the *Draft CERs* to install CCS without the concern that the technology might not achieve the 30t/GWh performance standard and enable the continued operation of the generating unit.[50]

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44 *Ibid* at 9.
45 When load-following, the unit ramps up and down to fill in when renewables are not producing, or when demand is very high.
46 ECCC, "Update," *supra* note 20 at 5.
47 *Ibid* at 7.
48 *Ibid* at 10.
49 *Ibid*.
50 *Ibid* at 7.

3. END OF PRESCRIBED LIFE

The Update also indicated that federal government is considering "slightly extending" the 20 year end-of-prescribed life to reduce stranded asset costs and allowing units that have substantial investment and work underway, but are unable to achieve commissioning by 1 January 2025, to make use of the end-of-prescribed life provisions of the *Draft CERs*, provided such units achieve commissioning by a set date (to be determined) as opposed to compliance as of 1 January 2035.[51] The Update contemplated that the end-of-prescribed life for such units would be shortened to ensure the units are subject to the *CERs* no later than a unit commissioned by 1 January 2025.[52]

The *Draft CERs* provide limited exemptions from the application of the Emissions Prohibition — for example, in respect of Behind the Fence generating units with no net exports or generating units granted, an exemption may be granted by the Minister due to an emergency circumstance.[53] A further exemption for peaking units[54] would allow such units to operate for a total emissions threshold of 150 kilotonnes of CO_2 per year, and maximum hour threshold of 450 hours per year (or 18.75 days) to address peak or back-up generating capacity.[55] The Update indicated the federal government is *evaluating* changes to the scope of the exempted categories to allow for more flexibility, and contemplating allowing system operator declarations of emergencies.[56] The Update also opined that the potential for "pooling" of units owned by a single entity may avoid the need to prescribe a time limit for peaker units.[57] However, the unconstructive result is that these amendments remain in flux.

In light of the changes under consideration, considerable uncertainty remains regarding the restrictions to be imposed in the final regulations and how they will be applied.

B. ENFORCEMENT

The *Draft CERs* would make non-compliance with the Emission Prohibition an offence under the *CEPA*, punishable by fines from \$100,000 to \$12 million or incarceration.[58] As part of the consultation process for the *Draft CERs*, stakeholders expressed significant concern regarding the potential for criminal liability for non-compliance, particularly in

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51 *Ibid* at 8.
52 *Ibid*.
53 *Draft CERs*, *supra* note 3, 2827–28, 2843–45 (proposed sections 5 and 19–20).
54 Peaking power plants, or "peaker plants," are power plants that generally run only when required to meet high or peak demand for electricity.
55 *Draft CERs*, *supra* note 3 at 2828 (proposed section 6(3)).
56 ECCC, "Update," *supra* note 20 at 7–9.
57 *Ibid* at 8.
58 *Draft CERs*, *supra* note 3 at 2851 (proposed section 31 states that "the schedule to the *Regulations Designating Regulatory Provisions for Purposes of Enforcement (Canadian Environmental Protection Act, 1999*) is amended by adding" subsections 6(1)–(3) of the *Draft CERs* as item 42). Proposed subsections 6(1)–(3) of the *Draft CERs* (*ibid* at 2828) set out the Emission Prohibition and exceptions regarding CCS and hours of operation. The provisions in the schedule of the *Canadian Environmental Protection Act, 1999*, SC 1999, c 33 [*CEPA*] are designated as offences under section 272(1)(h) of *CEPA* (*CEPA*, *ibid*, s 286.1). See also *CEPA*, *ibid*, s 272(3) (establishes significant penalties for persons other than individuals); *CEPA*, *ibid*, s 272.2(1) (provides for the potential incarceration of individuals who commit offences).

light of the stringency and complexity of the *Draft CERs*.[59] Many stakeholders identified the need for the ability to use emission offsets to achieve compliance.[60] The Update identified that consideration is being given to allow a unit to emit over its emissions limit by a prescribed amount, provided it remits GHG offsets to account for such excess emissions.[61] However, the Update did not identify the extent of the prescribed amount or the criteria for acceptable offsets.

C. CONSTITUTIONAL QUESTIONS

Not surprisingly, the *Draft CERs* prompted vociferous backlash from the provincial governments with electricity systems most reliant on emitting sources of generation — including claims of unconstitutionality. Under the *Constitution Act, 1867*, provinces have exclusive jurisdiction over the development, conservation, and management of sites for the generation and production of electricity, and shared jurisdiction with the federal government over the export of electrical energy.[62]

Alberta Premier Danielle Smith introduced and passed a motion in the Legislative Assembly of Alberta for a resolution under the as-yet untested *Alberta Sovereignty within a United Canada Act*[63] to bar enforcement of the regulation's restrictions.[64] Among other things, the resolution requested that Alberta's cabinet order all provincial entities to not recognize the constitutional validity of the proposed *Draft CERs* and to not enforce them or co-operate in their implementation in any manner "to the extent legally permissible," indicating that Alberta should also use all legal means necessary to oppose the *Draft CERs*, including legal challenges.[65] The resolutions also suggest that the government establish a provincial Crown corporation to ensure reliable and affordable electricity supply — by either building new generation or purchasing and de-risking existing generation assets held by private industry that would be subject to the *Draft CERs*.[66]

In his response to the *Draft CERs*, Saskatchewan's Minister of Crown Investments Corporation likewise called the regulations a contravention of section 92A(1) of the *Constitution Act, 1867*, a "concerning example of federal jurisdictional overreach," and an impermissible intrusion on the governance of its provincial Crown-owned utilities.[67] In the fall of 2023, Saskatchewan passed *The Saskatchewan First Act*,[68] with an objective to "defend [Saskatchewan] … from federal overreach."[69] "*The Saskatchewan First Act* amends the Constitution of Saskatchewan to clearly confirm Saskatchewan's autonomy and assert Saskatchewan's exclusive legislative jurisdiction under section 92 (A) of the

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59 Government of Canada, "*Draft CERs* General Comment Section," *supra* note 39.
60 *Ibid*.
61 ECCC, "Update," *supra* note 20 at 7.
62 *Constitution Act, 1867*, *supra* note 7, ss 92A(1)(c), 92A(2), 92A(3).
63 SA 2022, c A-33.8 [*Sovereignty Act*].
64 Alberta, Legislative Assembly, *Order Paper*, 31-1 (28 November 2023) at 4.
65 *Ibid* at 6.
66 Alberta, Legislative Assembly, *Votes and Proceedings*, 31-1, No 20 (28 February 2024) at 5–8.
67 Letter from the Honourable Dustin Duncan to the Honourable Steven Guilbeault (2 November 2023) at 4, online (pdf): [perma.cc/Y9CY-FTJD].
68 SS 2023, c 9.
69 Government of Saskatchewan, News Release, "Province Passes Saskatchewan First Act" (16 March 2023), online: [perma.cc/Y74X-W9HA] [GOS, "Province Passes SFA"].

Constitution of Canada."[70] Among other things, under section 3(3)(d) of *The Saskatchewan First Act*, Saskatchewan asserts exclusive jurisdiction over "the operation of sites and facilities in Saskatchewan for the generation and production of electrical energy," including "the source of fuel for electrical generation."[71] Part 3 of *The Saskatchewan First Act* establishes an independent Economic Impact Assessment Tribunal for the purposes of defining, quantifying, and reporting on the economic effects of federal initiatives of provincial investments and Saskatchewan projects, businesses, and people.[72] On 25 June 2024, following the Economic Impact Assessment Tribunal's report on the *Draft CERs*, Saskatchewan announced that it would not be complying with the *Draft CERs* when they come into effect, on the basis that the *Draft CERs* would cost the province $7.1 billion, at least 4,200 jobs, and "an $8.1 billion negative effect on Saskatchewan's export sector."[73]

The constitutionality of the *Draft CERs* was also raised in other stakeholder comments, including a recommendation that the regulations be referred to the Supreme Court of Canada to determine their constitutionality prior to implementation in light of the Supreme Court of Canada's ruling regarding the *Impact Assessment Act*.[74]

While the Update indicated that the final *CERs* may introduce additional flexibility, it remains apparent that significant restrictions on unabated emitting generation will still be legislated in the *CERs*, whatever their final form. The federal government provided no indication in the Update, or otherwise, that it is considering walking back the prescribed restrictions in the *Draft CERs*. It would not be unexpected if Alberta or other significantly impacted provinces such as Saskatchewan seek to challenge the final *CERs* regardless of the nature or scope of the remaining restrictions on emitting electricity generation.

III. SUPPLY ADEQUACY: RESTRUCTURING AND RISK ALLOCATION

Canadian jurisdictions from coast-to-coast-to-coast are planning for aggressive growth of their electricity supply to meet increased electrification demands in support of economy-wide carbon reduction targets, and are experiencing transitional impacts arising from changes in generation supply mix. Many Canadian provinces, regardless of their electricity frameworks, are experiencing reliability and affordability challenges that are becoming more significant as the pace of change increases. Further complicating this transition are the restrictions proposed in the *Draft CERs*. According to RIAS, if the *Draft CERs* are implemented, electricity systems in Alberta, Saskatchewan, Ontario, Nova Scotia, and New Brunswick would be mandated to implement an estimated 98 percent of incremental

70 *Ibid*.
71 *Supra* note 68, s 3(3)(d).
72 *Ibid*, ss 6–12. See also GOS, "Province Passes SFA," *supra* note 69.
73 Government of Saskatchewan, News Release, "Sask First Tribunal Releases Report: Federal Clean Electricity Regulations Would Cost Province $7.1 Billion" (25 June 2024), online: [perma.cc/9EJZ-ADQB].
74 Pathways Alliance, "The Pathways Alliance (Pathways) submits the following technical comments ..." (2 November 2023), online: [perma.cc/MM6R-TDMY].

emission reductions from 2024 to 2050[75] — these are the five provinces with electricity systems most reliant on electricity generated using fossil fuels.[76]

In response to the *Draft CERs* and other market forces, jurisdictions across Canada are introducing new measures and means of meeting resource adequacy in the medium and longer term. These measures include market restructuring initiatives, competitive procurements, and more direct government assumption of risk for compliance.

In Alberta, the imposition of restrictions on investment in emitting sources of electricity generation, significant investment in renewable generation, and the entrance of new market participants are causing the government to review all aspects of electricity generation and transmission policy.

A Grid Alert[77] issued by the Alberta Electric System Operator (AESO) on 5 April 2024 illustrates the complexity of resource reliability and adequacy in Alberta, even absent the *Draft CERs*. The Grid Alert was issued due to tight generation supply.[78] According to AESO, the available solar and wind generation was 900 MW below forecast at a time when several thermal generating units were on planned outages.[79] During this same period, another thermal natural gas fired generating unit tripped, experiencing an unplanned outage, resulting in the loss of an additional 400 MW of generation.[80] Other thermal generating units were taking time to ramp up and return to service, and AESO had dispatched available Operating Reserve, calling on all available generation and contracted load shed services.[81] Electricity was also imported to address the supply deficit.[82] However, rolling outages were still required throughout the province until normal operations resumed several hours later.[83] This Grid Alert demonstrates the complexities of balancing Alberta's generation supply mix, even absent the *Draft CERs*.

The Government of Alberta's policy is directed at achieving a net-zero economy, including a net-zero grid, by 2050, not 2035.[84] Nonetheless, in its 2024 Long-Term Outlook, AESO included a "[d]ecarbonization by 2035 scenario" that would align with the

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75 RIAS, *supra* note 18 at 2758–59.

76 *Ibid* at 2791.

77 "Grid Alerts are issued when the Alberta power system is under stress, and [AESO is] preparing to use emergency reserves to meet demand and maintain system reliability": Alberta Electric System Operator, "Grid Alert Notifications," online: [perma.cc/5WBB-6HW2] [AESO, "Grid Alert Notifications"].

78 Alberta Electric System Operator, "Media Briefing: Overview of the Grid Alerts" (5 April 2024), online (video): [perma.cc/78UA-2497] [AESO, "Media Briefing"].

79 *Ibid* at 2:50–3:50.

80 *Ibid*.

81 AESO procures Operating Reserve from generators or loads to maintain system reliability when there is an unexpected imbalance between supply and demand. Operating Reserves are categorized as regulating, spinning, or supplement reserves. AESO procures active and standby volumes of each type of Operating Reserve from a competitive market: Alberta Electric System Operator, "Operating Reserve," online: [perma.cc/T5AM-WC2B].

82 AESO, "Media Briefing," *supra* note 78.

83 The Grid Alert was issued at 6:49 a.m. and ended at 11 a.m. on 5 April 2024: AESO, "Media Briefing," *ibid* at 2:50–3:50. According to AESO, 250 MW of load was taken off-line for 20 to 30 minutes at a time by working with the distribution utilities: AESO, "Media Briefing," *ibid* at 3:15–3:35.

84 Environment and Protected Areas, *Alberta Emissions Reduction and Energy Development Plan* (Edmonton: Government of Alberta, 2023) at 6.

Draft CERs restrictions.[85] This scenario would require approximately 25,000 MW of generation capacity additions and retrofits between 2024 and 2041, which is similar to forecast capacity additions under AESO's reference case (which aligns with the provincial government's target to achieve decarbonization by 2050).[86] However, the AESO models that the decarbonization by 2035 scenario has a much higher risk of supply shortfall and unserved energy, and the development of alternative generation technologies have higher costs and lesser technological maturity.[87]

As has been the subject of much reporting, on 3 August 2023, one week in advance of the release of the *Draft CERs*, the Government of Alberta enacted the *Generation Approvals Pause Regulation*, requiring the Alberta Utilities Commission (AUC) to immediately pause approvals of new renewable electricity generation projects over one megawatt until 29 February 2024.[88] Concurrently, the Alberta Minister of Utilities and Affordability directed AESO and the Market Surveillance Administrator to study the current energy market framework in Alberta.

AESO's recommendation report titled "Alberta's Restructured Energy Market: AESO Recommendation Report" (the REM Report)[89] identified, among other things, that structural change to the Alberta market design and provincial electricity policy is needed and being driven by a combination of: technological shift, generation investment driven by environmental attributes, and uncertainty for gas-fired controllable[90] generation due to the proposed *Draft CERs*.[91] In terms of resource adequacy, the current Alberta Energy Only Market (EOM) relies on private investment in new generation to ensure long-term supply adequacy by attracting needed investments primarily through wholesale energy prices.[92] The REM Report describes that Alberta, like other jurisdictions, is experiencing a significant shift from carbon-emitting controllable generation sources to variable renewable generation resources (namely, wind and solar), and that although renewables support a carbon-neutral future, they must be supported with controllable resources.[93] Among other recommendations, the REM Report proposes several changes to the EOM, including calling it the Restructured Energy Market, or REM. According to the REM Report, the two mechanisms most relevant to strengthening incentives for investments in dispatchable technologies are:

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85 Alberta Electric System Operator, *AESO 2024 Long-Term Outlook* (Calgary: AESO, May 2024) at 8, online (pdf): [perma.cc/DW67-RTWU] [AESO, "2024 LTO"].

86 *Ibid* at 8.

87 *Ibid* at 15.

88 *Generation Approvals Pause Regulation*, Alta Reg 108/2023.

89 Alberta Electric System Operator, *Alberta's Restructured Energy Market: AESO Recommendation to the Minister of Affordability and Utilities* (Calgary: AESO, 31 January 2024), online (pdf): [perma.cc/TAF9-U6L6] [AESO, "REM Report"].

90 *Ibid* at 2, n 1 ("[w]hen referring to different types of supply, the terms dispatchable and controllable are used interchangeably to represent technologies that can be dispatched and controlled in real time.")

91 *Ibid* at 15.

92 *Ibid* at 13.

93 *Ibid* at 16. Low carbon emission controllable resources include abated natural gas generation, hydrogen-fueled generation, full-scale nuclear, small modular reactors, hydroelectric power, and energy storage resources (*ibid* at 41–45).

- the implementation of "a scarcity-based administrative pricing mechanism and a day-ahead energy market," which are proposed to be implemented in the medium term (two to five years);[94] and

- "[t]he option to directly contract for controllable supply if needed in the long-term to ensure reliability," which is "only [to] be used if REM changes are ineffective in [incenting] the required investment."[95]

The introduction of a day-ahead market represents a significant change to the Alberta EOM, under which suppliers are currently able to change volumes at any time with an acceptable operational reason and can change their offer price up to *two hours* before the settlement interval.[96] The REM Report proposed that a centrally cleared day-ahead market would commit generation to meet forecasted load.[97] All generation types would offer their expected available generation in the day-ahead market. According to the REM Report, generators that clear in the day-ahead market would be guaranteed a price for producing to their schedule, providing sellers with certainty that daily revenues can cover their short-term costs regardless of real-time price conditions.[98] Generators that clear in the day-ahead market but are not available in real time may be obligated to pay for the shortfall in their delivered volumes at the real-time energy price. According to the REM Report, this will create incentives for dispatchable technologies to operate by providing a more certain revenue stream and production schedule, and for non-controllable resources (namely, wind and solar) to become more dispatchable and better at forecasting production.[99]

As an optional measure, the REM Report also proposes direct contracts for controllable supply if needed in the long-term to ensure reliability.[100] The REM Report is clear that this is only for targeted procurements on an as-needed basis, and only in the event of inadequate market investment in controllable supply.[101] Further, in keeping with comments of Alberta Premier Danielle Smith, the REM Report notes that decarbonization policies, such as the *Draft CERs*' strict requirements, introduce significant uncertainty for investment in some controllable technologies such as CCS.[102] The REM Report notes that more direct

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94 *Ibid* at 26.
95 *Ibid*.
96 Using the price-quantity offers, a merit order is created by sorting offers from the lowest priced to the highest priced for each hour of the day. AESO dispatches the lowest priced offers from the bottom of the merit order first and move up toward the higher priced offers until all electricity required to meet demand has been dispatched. The last offer dispatched to meet demand sets the system marginal price (SMP) for electricity. For example, if offers in the merit order are priced from $0 to $100 and the last offer dispatched to meet demand is priced at $40, the SMP is $40. The SMP is set on a minute-to-minute basis and is used in the calculation of the hourly settlement price, also known as the pool price. The pool price is calculated as the average of all 60 one-minute SMPs in each hour and is posted at the end of the hour: Alberta Electric System Operator, "Guide to Understanding Alberta's Electricity Market," online: [perma.cc/JK8K-FWPJ].
97 AESO, "REM Report," *supra* note 89 at 29.
98 *Ibid* at 30.
99 *Ibid*.
100 *Ibid*.
101 *Ibid* at 31.
102 *Ibid* at 33.

government support or ownership may be appropriate to financially underpin the investment or assign a liability to the province.[103]

The Alberta Minister of Affordability and Utilities has directed AESO to develop a draft technical design of the proposed REM on an expedited timeframe by the fall of 2024.[104] At the time of writing, the REM measures were still subject to further refinement and modification. For the time being, Alberta intends to rely on private investment in new generation to ensure long-term supply adequacy, albeit with a restructured market intended to provide additional incentives.[105] Should the *Draft CERs* be passed, more direct government intervention is anticipated.

Alberta is not alone in examining and implementing new measures to ensure that resource adequacy requirements are met in the lead up to 2035 and beyond. Differing approaches to addressing the implications of the *Draft CERs* are evident, particularly in those jurisdictions most impacted.

Ontario provides an example of a provincial jurisdiction with a large fleet of non-emitting generation (nuclear, hydro, and significant wind and solar facilities) that is nonetheless also grappling with resource adequacy in the near term. In its submission on the *Draft CERs*, the Ontario Independent Electricity System Operator (IESO)[106] stated that the *Draft CERs* are unachievable in Ontario by 2035 without putting at risk the reliability of the electricity system, electrification of the broader economy, and economic growth.[107] Ontario's decarbonization plan includes the procurement of energy storage capacity; refurbishments of its existing nuclear fleet; implementing small modular reactors, with the first underway at the Darlington Nuclear Generating Station; hydroelectric generation; additional renewable generation (wind, solar, and bioenergy); energy efficient enhancements and distributed generation; natural gas generation until nuclear refurbishments are complete; and, "new non-emitting technologies such as storage mature."[108] IESO's planning scenario for a decarbonized grid forecasts that 8,000 MW of natural gas generation (17 percent of Ontario's installed capacity) will need to remain available in 2035 to ensure system reliability until other generation alternatives are identified and in service.[109]

Approximately 31 percent of Ontario's connected capacity is nuclear but it accounts for almost half of the total electricity output annually.[110] While the refurbishments aim to secure long-term supply, a significant portion of Ontario's nuclear supply will be taken off-

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103 *Ibid*.
104 Letter from the Honourable Nathan Buffin to Mike Law (11 March 2024), online: [perma.cc/M2RB-R72E].
105 AESO, "REM Report," *supra* note 89 at 47.
106 IESO is responsible for operating the electricity market and directing the operation of the bulk electrical system in Ontario.
107 Independent Electricity System Operator, News Release, "The IESO's Response to Draft Clean Electricity Regulations" (16 November 2023), online: [perma.cc/8V6T-3W8Y] [IESO, "IESO Response"].
108 Government of Ontario, *Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future* (Toronto: Government of Ontario, 2023) at 43, 49 [Government of Ontario, *Powering Ontario's Growth*].
109 IESO, "IESO Response," *supra* note 107.
110 Government of Ontario, *Powering Ontario's Growth*, *supra* note 108 at 14–15.

line in the short term for refurbishment.[111] "At [its] peak, four nuclear units will be down at one time, representing about nine percent of Ontario's generating capacity," during which time, "electricity demand will be met [significantly] by natural gas generation and … energy storage battery projects."[112] Ontario has long-term contracts underpinning its electricity industry, with generation developed by both private entities and a Crown corporation.[113] Nearly all electricity generation is utility-owned (rate-regulated) or secured via long-term contracts.[114] In 2022, the Ontario government issued a direction to IESO under the *Electricity Act* to undertake procurement of electricity resources to ensure reliability, including natural gas-fired electricity resources.[115] To address the anticipated impact of future regulation of, and restrictions on, natural gas-fired generation, the direction included the requirement that associated procurement contracts:

> [I]nclude provisions … that, where laws or regulations are introduced and passed restricting GHG emissions from a project:
>
> i. Require such projects to submit GHG emissions abatement plans, showing how the project will bring its operations into compliance with the laws or regulations, prior to the new emissions standards coming into force; and
>
> ii. If a project is unable to comply with such laws or regulations in order to continue meeting its obligations under the Contract, despite commercially reasonable efforts, allow such project to suspend operations for the balance of the contract term while retaining payments under the Contract.[116]

In 2023, the IESO announced that it had awarded contracts for new natural gas fired generating facilities at existing locations within Ontario, capacity upgrades at existing facilities, and contract extensions to existing natural gas fired facilities.[117] In compliance with the direction, the form of contract includes an obligation on IESO to continue payments to the natural gas generation facility owner in the event that the facility operation is restricted or it is decommissioned early due to the *Draft CERs* or similar legislation.[118] What is clear from the IESO procurement is that the Government of Ontario is willing to have IESO, or customers, assume the risk of compliance with the *Draft CERs* and stranded costs in its pursuit of near term resource adequacy.

Saskatchewan, like Ontario, signaled an intention to continue to rely on natural gas generation in the medium term. Saskatchewan has announced its plans to reach net-zero generation by 2050, calling the *Draft CERs* and net zero by 2035 "unrealistic and

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111 *Ibid* at 42–43.
112 *Ibid* at 43.
113 *Ibid* at 43.
114 AESO, "REM Report," *supra* note 89 at 32.
115 *Electricity Act*, SO 1998, c 15, Schedule A, ss 25.3(2), 25.4; Government of Ontario, "Directive: Order in Council 1348/2022," (21 October 2022), online: [perma.cc/PK5S-FBJX].
116 *Electricity Act*, *ibid*.
117 Independent Electricity System Operator, "IESO Resource Adequacy Update" (16 May 2023), online: [perma.cc/9623-G37G].
118 Independent Electricity System Operator, "Long-Term Reliability Services 1 (LT1) Contract" (29 September 2023) at 43–45, online (pdf): [perma.cc/4ADY-SHQ9].

unaffordable."[119] SaskPower[120] has indicated that its decarbonization pathway between 2023 and 2025 includes adding additional renewables generation, battery energy storage, expanding imports, developing nuclear small module reactors, and adding approximately 1,500 MW of natural gas-fired generation to replace coal assets being retired.[121] To comply with the *Draft CERs*, SaskPower stated that it would need to expand, replace, and rebuild "the majority of [its] current [power] generating capacity of more than 5,400 [MW] … in just over 11 years" while also significantly expanding its transmission infrastructure — which it states is "is not possible from technological, financial and logistical perspectives."[122] SaskPower is further developing a long-term plan to meet Saskatchewan's GHG emissions targets of net-zero emissions by 2050 and a 2030 emissions reduction target of 50 percent below 2005, which is expected to be released 2024.[123]

Like Saskatchewan, Nova Scotia has historically been heavily reliant on coal-fired generation. The Nova Scotia provincial government has mandated the closure of coal-fired generation by 2030 and will require 80 percent of electricity to be produced from renewable sources by 2030.[124] On 20 April 2023, Nova Scotia Premier Tim Houston and Natural Resources and Renewables Minister Tory Rushton announced the establishment of the Clean Electricity Solutions Task Force (CESTF).[125] CESTF was directed to, amongst other things, examine electricity infrastructure needs to ensure reliability, capacity, and storage to meet Nova Scotia's emission reduction targets.[126] On 23 February 2024, it released a final report (the NS Task Force Report).[127] CESTF concluded that transitioning electricity generation from coal to renewables will require very significant investments in new energy generation in Nova Scotia, and that competitive processes conducted by an independent system operator — a role historically undertaken by Nova Scotia Power Inc. (NS Power)[128] — are required to ensure that competitive investment is attracted.[129] Among other recommendations, the NS Task Force Report recommended the creation of a new Nova Scotia Independent Energy System Operator to oversee open competition for procurement of all new infrastructure, including for generation, transmission, distribution, and storage, in which NS Power would not be excluded from participating.[130]

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119 Government of Saskatchewan, News Release, "Premier Outlines Plans for Affordable, Reliable Power Production" (16 May 2023), online: [perma.cc/MMK7-5MUP].

120 SaskPower is a vertically integrated Crown corporation, responsible for generation, transmission, and distribution of electricity in Saskatchewan.

121 SaskPower, "Response Appendix," *supra* note 41 at 8.

122 Letter from Rupen Pandya to the Honourable Steve Guilbeault (2 November 2023) at 1, online: [perma.cc/GE6J-F4BF] [SaskPower Response Letter].

123 SaskPower, "Response Appendix," *supra* note 41 at 7.

124 Government of Nova Scotia, "Nova Scotia's 2030 Clean Power Plan" (2023) at 13, online (pdf): [perma.cc/2XG6-ADAK] [GNS, "Nova Scotia's 2030"].

125 Government of Nova Scotia, News Release "Seeking Solutions for Clean Electricity" (20 April 2023), online: [perma.cc/D6Y2-3AA6].

126 *Ibid*.

127 Nova Scotia Clean Electricity Solutions Task Force, *Modernizing Energy from Transition to Transformation: A Report of the Clean Electricity Solutions Task Force*, by Alison Scott & John MacIsaac (Halifax: NSCESTF, 31 January 2024).

128 Nova Scotia Power Inc. (NS Power) is an investor owned vertically integrated utility, owning 79 percent of the provincial generation capacity of all transmission assets and a significant portion of the distribution system.

129 Nova Scotia Clean Electricity Solutions Task Force, *supra* note 127 at 30.

130 *Ibid* at 30–31.

On 5 April 2024, the Nova Scotia Legislature passed Bill 404, the *Energy Reform (2024) Act* to implement the recommendations of the NS Task Force Report.[131] *ERA 2024* introduces significant changes to energy regulation and governance in Nova Scotia to support the shift to renewable energy generation and electrification. *ERA 2024* creates two new acts (the *Energy and Regulatory Boards Act* and the *More Access to Energy Act*), establishes two new regulators (the Nova Scotia Energy Board and the Regulatory and Appeals Board), and creates the Nova Scotia Independent Energy System Operator to manage the operations formally performed by NS Power.[132] *ERA 2024* also removes obstacles to NS Power's ownership of nuclear generating stations and mandates public procurements for energy resources for all large-scale utilities.[133] The legislation and amendments enacted by *ERA 2024*, including the shift to an independent system operator, constitute a significant change to the electricity regulation framework in Nova Scotia and will take time to operationalize.

Regardless of whether the goal is for a net-zero grid by 2050 or by 2035, with increased electrification demands, adherence to the status quo is unlikely to support the required investments. It is anticipated that the implementation of different mechanisms to support investment — including market restructuring and framework reforms, government intervention, and public assumption of regulatory risk to facilitate electrification and energy transition — is a trend that will continue.

IV. MANAGING THE TENSION BETWEEN POLICIES FOR INCREASED ELECTRIFICATION AND SCARCITY OF SUPPLY

The *Draft CERs*' restrictions on electricity generation that is not low or non-emitting also have the potential to conflict with various policy directives intensifying demands for electrification. The RIAS cost-benefit-analysis modelled that electricity demand will increase by 40 percent over the analytical period (2024 to 2050), while acknowledging that other studies had previously estimated that electricity demand could triple by 2050.[134] The 2023 federal budget indicated that Canada's demand is expected to double by 2050, and overall installed capacity would need to increase by 2.2 to 3.4 times compared to current levels to meet demand by 2050.[135]

In Alberta, electrification and new industrial load are expected to drive energy consumption increases. On 27 June 2022, AESO published a detailed analysis of the opportunities and challenges involved in eliminating GHG emissions from Alberta's power system — the *AESO Net-Zero Emissions Pathways Report* (the AESO Net-Zero Report).[136] The AESO Net-Zero Report notes that the impact of net-zero policies on electricity load in Alberta is uncertain and difficult to forecast, acknowledging that there are differing views

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[131] SNS 2024, c 2 [*ERA 2024*].
[132] *Ibid*, ss 2–3, Schedule A, Schedule B.
[133] *Ibid*, ss 52, 66.
[134] RIAS, *supra* note 18 at 2711, 2790.
[135] Department of Finance Canada, *Budget 2023: A Made-In-Canada-Plan*, Catalogue No 1719-7740 (Ottawa: DFC, 2022) at 77.
[136] Alberta Electric System Operator, *AESO Net-Zero Emissions Pathways Report* (Calgary: AESO, June 2022), online (pdf): [perma.cc/HC2G-QUZN] [AESO, "Net-Zero Report"].

on petroleum production, which have historically been significant drivers of industrial electricity demand.[137] However, among other findings, the AESO Net-Zero Report concludes that electrification of industrial processes, heating, and transportation will drive electricity demand growth in Alberta over the next two decades.[138] Even considering the potential for lower electricity demand from the petroleum sector, and the increased adoption of distributed energy resources (such as rooftop solar) that offset Alberta internal load, compared to 2021, load is expected to increase by 15 percent by 2035 and 25 percent by 2041.[139] AESO's 2024 Long-Term Outlook predicts that average hourly Alberta internal load will increase by approximately 26 percent from 2024 to 2043 in the reference scenario, and by 43 percent in a high electrification scenario (reflecting increased electric vehicle adoption, building heating and cooling electrification, hydrogen production, and electrification of heavy industry).[140]

Indeed, multiple jurisdictions, including the federal government, have deployed various policy levers to encourage higher use of electricity in place of other emitting fuel or energy sources. As noted in the AESO Net-Zero Report, a significant driver of electricity demand is expected to be the conversion to electric vehicles.[141] For example, Canada has also amended the *Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations*, which will mandate that a specified portion of new light-duty vehicles sold by manufacturers and importers in Canada be zero-emissions vehicles, with the required percentage increasing over time.[142] Furthermore, the federal government, British Columbia, New Brunswick, Newfoundland and Labrador, Nova Scotia, Prince Edward Island, Quebec, and the Yukon currently offer rebates and incentives related to electric vehicles.[143]

The AESO Net-Zero Report identifies that another driver of electrical demand will be the "electrification of heating systems via 'fuel-switching' from natural gas to electric heat pumps."[144] While the AESO Net-Zero Report acknowledges that in Alberta, the implementation of building net-zero solutions is challenged by the lack of regulatory direction and limited incentives,[145] other Canadian jurisdictions have taken more concrete steps to encourage fuel-switching and building decarbonization. For example, British

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137 *Ibid* at 15.
138 *Ibid* at 1.
139 *Ibid* at 23.
140 Alberta Electric System Operator, "Results: Reference Case: AESO 2024 Long-Term Outlook" (May 2024) at 2, online (pdf): [perma.cc/N2MX-5FFB]; Alberta Electric System Operator, "Results: High Electrification: AESO 2024 Long-Term Outlook" (May 2024) at 2, online (pdf): [perma.cc/8MTZ-LH8Y].
141 AESO, "Net-Zero Report," *supra* note 136 at 16, 25.
142 *Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations*, SOR/2010-201 as amended by 2023-275, s 30.12
143 Government of Canada, "Zero-Emission Vehicles: Incentives," online: [perma.cc/HUJ7-VAAZ]. See also Government of Yukon, "Apply for a Shipping Rebate for a Used Zero-Emission Vehicle," online: [perma.cc/AM8B-5V8V].
144 AESO, "Net-Zero Report," *supra* note 136 at 19.
145 *Ibid*.

Columbia and Quebec are taking steps to increase energy-efficiency requirements in buildings,[146] and several jurisdictions have introduced rebates for heat pumps.[147]

The International Energy Agency has highlighted that electricity consumption by data centres, artificial intelligence, and the cryptocurrency sector are significant drivers of increasing electricity demand and projected to double globally by 2026.[148] This corresponds roughly to the equivalent of adding the 2022 electricity demand of Germany by 2026. Data centres are significant drivers of electricity demand, but the artificial intelligence industry is expected to grow exponentially and consume at least ten times its 2023 demand by 2026.[149] While much of this growth has been in other jurisdictions, several Canadian provinces have already implemented restrictions on, or suspended the connection of, new cryptocurrency developments to electricity grids to prioritize electrification of other loads that align with policy objectives.[150]

The restrictions on cryptocurrency load may be a harbinger of a broader trend. In Quebec, like Alberta, the guiding principle in electricity supply has been that Hydro-Québec is required to distribute electric power to every person who requests service within its territory, per the *Act respecting the Régie de l'énergie*.[151] However, Bill 2 modified the *Act respecting the Régie de l'énergie* by amending the guiding principle of mandatory electricity supply upon request and granting the Minister of Economy, Innovation, and Energy the discretionary power to select the industrial projects that require supply by Hydro-Québec of electricity in excess of 5 MW.[152] Bill 2 provides that such selection must be made by the Minister considering Hydro-Québec's technical capabilities as well as the economic benefits and social and environmental impacts of the use of the electric power requested.[153] The measure stems from the incapacity of Hydro-Québec to match the electricity demand from ever more energy-intensive industrial projects,[154] and the Government of Quebec's objective to attain net-zero emissions by 2050.[155]

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146 Government of British Columbia, "Energy Efficiency" (24 April 2024), online: [perma.cc/7YFB-SWZB]. See also Quebec's Bill 41, which has targets of reducing greenhouse gas emissions in the buildings sector: Bill 41, *An Act to enact the Act respecting the environmental performance of buildings and to amend various provisions regarding energy transition*, 1st Sess, 43rd Leg, Quebec, 2024, c 5.

147 See e.g. CleanBC Better Homes, "Learn More About Heat Pumps," online: [perma.cc/6584-D7JC]. The federal government has introduced an oil-to-heat-pump affordability program for homeowners to transition from oil heating to new, energy-efficient heat pumps: Natural Resources Canada, "Oil to Heat Pump Affordability Program," online: [perma.cc/5T68-TCQD].

148 International Energy Agency, *Electricity 2024: Analysis and Forecast to 2026* (Paris: IEA, May 2024) at 8.

149 *Ibid*.

150 See e.g. *The Crown Corporations Governance and Accountability Act*, CCSM c C336, s 13; Bill 24, *Energy Statutes Amendment Act, 2024*, 5th Sess, 42nd Parl, British Columbia, 2024; *An Act to Amend the Electricity Act*, SNB 2023, c 37, amending SNB 2013, c 7, s 91(3).

151 CQLR c R-6.01, s 76.

152 Bill 2, *An Act mainly to cap the indexation rate for Hydro-Québec domestic distribution rate prices and to further regulate the obligation to distribute electricity*, 1st Sess, 43rd Leg, 2023, c 1 (assented to 16 February 2023), SQ 2023, c 1 [Bill 2].

153 *Ibid*, s 10.

154 Tommy Chouinard, "Demandes d'alimentation faites à Hydro-Québec: 1000 mégawatts pour 11 entreprises, annonce Pierre Fitzgibbon," *La Presse* (31 August 2023), online: [perma.cc/C5R5-77RT].

155 Gouvernement of Quebec, *Politique-cadre d'electrification et de lutte contre les changements climatiques* (Quebec City: Gouvernement of Quebec, 2020).

In the first of such allocations, Hydro-Québec was awarded the authorization to provide electricity service to 11 industrial projects, five of which are directly related to the electric vehicle battery industry, which has been an economic priority of the current Quebec government.[156] It was reported unofficially in February 2024 that at least 150 industrial projects were submitted to the Minister for review and approval for the next allocation,[157] but it is anticipated that only a select few projects will be greenlighted.[158] This approach has raised questions within Quebec as to the appropriate balance between electricity exports and the connection of industrial projects in the province.[159]

Measures restricting new load connections are an extension of more traditional methods of managing demand, such as efficiency improvements, time-of-use rates, and other demand-side management measures. All of these measures will likely see increasing adoption as a means to manage electricity demand in the face of potential supply inadequacy, even absent the imposition of the *Draft CERs*. If the *Draft CERs* are implemented and enforced by 2035, and needed investment for replacement-abated or non-emitting generation lags, then impacted jurisdictions may be forced to adopt increasing stringent measures to allocate electricity if faced with inadequate supply.

V. INTERTIES, IMPORTS, EXPORTS, AND REGIONAL CO-OPERATION

According to RIAS, the *Draft CERs* are expected to result in a significant increase to domestic electricity trade activity, facilitated by new provincial interties to minimize the system-wide compliance costs.[160] RIAS models that domestic trade would increase by $43 billion in economic value from 2024 to 2050, which is a 17 percent increase compared to baseline assumptions.[161] Alberta is projected to see an estimated net import expenditure of $16.3 billion over that time period, whereas British Columbia is projected to see estimated cost savings of $21.7 billion, while other provinces can expect to see cost impacts or savings falling somewhere in between.[162] RIAS estimates that that the proposed *Draft CERs* would result in a total of $6.7 billion of incremental capital costs for new interprovincial transmission lines to 2050, with the majority of these costs being incurred by Ontario, Manitoba, Alberta, and British Columbia.[163]

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156 Office of the Minister of Economy, Innovation and Energy & Minister of Regional Economic Development, News Release, "Attribution responsable et durable de notre électricité — Québec dévoile la liste des onze projets sélectionnés pour un raccordement d'une puissance de 5 MW et plus" (10 November 2023), online: [perma.cc/CWJ3-PLWK].

157 Dominique Talbot, "Les entreprises se bousculent pour les mégawatts d'Hydro-Québec," *Les Affaires* (13 June 2024), online: [perma.cc/NWN7-SHKR].

158 Chouinard, *supra* note 154.

159 Bloomberg News, "Quebec Faces Big Electricity Shortfall After Wooing U.S. to Buy Cheap Hydro Power," *Financial Post* (27 April 2023), online: [perma.cc/4SFG-MS3W].

160 RIAS, *supra* note 18 at 2781.

161 *Ibid*.

162 *Ibid* at 2782.

163 *Ibid* at 2769.

The federally appointed Clean Electricity Advisory Council[164] has also identified that wider regional integration, combined with multi-jurisdictional planning and coordination, has the potential to support reliability and resilience goals at lower overall costs than other available solutions.[165] However, provincial grids have historically evolved with limited consideration for inter-regional co-operation within Canada. Canadian interties (transmission lines that connect separate electric grids and enable the trade of electricity between jurisdictions) generally have greater capacity going north to south — that is, between the United States and Canada — than east to west.[166]

Alberta's comments on the *Draft CERs* indicate that RIAS has overly optimistic assumptions about capacity and timelines for increased interties with British Columbia, given that "current ties are constrained and increasing intertie capability by significant volumes to balance intermittent generation across regions will take significant time and coordination between jurisdictions, beyond the 2035 horizon."[167] The Alberta Ministry of Affordability and Utilities has initiated a consultation through a green paper titled "Transmission Policy Review: Delivering the Electricity of Tomorrow" (the Green Paper), which, among other things, considers the treatment of interties in Alberta.[168] The Green Paper acknowledges that with intermittent generation increasing, interties can play a crucial role in achieving affordability, reliability, and decarbonization by: (1) allowing low priced imports to put downward pressure on pool prices; (2) providing "grid balancing, load management, and reserve capacity services"; and (3) allowing surplus clean electricity to be imported to and exported from Alberta to address supply surplus.[169] The Green Paper indicates that several measures are under consideration to amend the *Transmission Regulation* to provide clarity for interties — including changes to more clearly indicate when restoration of interties to their path rating must be completed, including the Alberta-British Columbia intertie[170] and amendments to outline Alberta's "intent to develop additional interties with its neighboring provincial and state jurisdictions and clarify how these developments may fit into the broader planning of the Alberta interconnect electricity system."[171] Despite the longstanding requirement in the *Transmission Regulation* to restore the Alberta-British Columbia intertie to its path rating, it has historically operated far below

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164 The federal Minister of Energy and Natural Resources created the Canada Electricity Advisory Council in May 2023 as an independent, electricity-sector focused expert advisory body to provide advice to the Minister of Energy and Natural Resources to accelerate investment, and promote sustainable, affordable, and reliable electricity systems: Natural Resources Canada, "The Canada Electricity Advisory Council," online: [perma.cc/P6F5-ZJ7C] [NRC, "Advisory Council"].

165 *Canada Electricity Advisory Council: Interim Report* (Ottawa: Canada Electricity Advisory Council, December 2023) at 6.

166 House of Commons, *Strategic Electricity Interties: Report of the Standing Committee on Natural Resources* (December 2017) (Chair: James Maloney).

167 Alberta, Environment and Protected Areas, *Federal Draft Clean Electricity Regulations: Government of Alberta Technical Submission* (Edmonton: Ministry of Environment and Protected Areas, 2024) at 16 [AEPA, *Federal Draft CERs*] (notes that the in RIAS, *supra* note 18, the model had 1,000 to 1,900 MW with British Columbia in 2034, and then to 2,700 MW in 2044).

168 Alberta, Ministry of Affordability and Utilities, *Transmission Policy Review: Delivering the Electricity of Tomorrow* (Edmonton: AMAU, 23 October 2023) at 21 [AMAU, *Green Paper*].

169 *Ibid*.

170 At the time of writing this article, section 16 required AESO to "prepare a plan and make arrangements to restore each intertie that existed on August 12, 2004 to, or near to, its path rating": *Transmission Regulation*, Alta Reg 86/2007, s 16.

171 AMAU, *Green Paper*, *supra* note 168 at 22.

this level.[172] In its response to the Green Paper, AESO has concurred that clarification regarding the volume and timing targets for restoring existing intertie capacity will "enhance the AESO's ability to move quickly towards solutions."[173]

In the *Draft CERs* consultation, Saskatchewan also stated that the RIAS modelling inaccurately assumed a barrier-free exchange of electricity between provinces, and that Manitoba would be a key partner in Saskatchewan's transition.[174] Saskatchewan called these assumptions flawed due to differing provincial electricity market structures, differing domestic priorities and export commitments, and inadequate interprovincial transmission capacity.[175] Nonetheless, Saskatchewan has identified that its decarbonization pathway includes adding at least 1,000 MW of low or non-emitting imports, and expanding regional transmission interconnections to facilitate imports.[176] However, Saskatchewan is not planning to rely solely on domestic trade. The province is planning a new international line to increase interconnection capacity between Saskatchewan and the Southwest Power Pool,[177] and in the fall of 2023 issued a request for supply proposals for up to 500 MW of power through the Southwest Power Pool.[178]

The conflict between differing provincial domestic priorities and export commitments is also apparent from a complaint brought by NorthPoint Energy Solutions Inc. (NorthPoint), a wholly owned subsidiary of SaskPower, currently before the Canada Energy Regulator.[179] The complaint alleged that the Manitoba Hydro-Electric Board (Manitoba Hydro) had not granted fair market access to electricity available for export (FMA) as required by a 2015 electricity export permit, which includes a condition essentially requiring Manitoba Hydro to inform Canadian purchasers of the quantities and classes of electricity available for sale, and an opportunity to purchase electricity on terms and conditions as favourable as the terms and conditions which apply to the proposed exports.[180] The complaint alleged that Manitoba Hydro had not allowed NorthPoint to purchase power on terms equivalent to its exports and, as a result, SaskPower must run its fossil fuel generation or purchase, through NorthPoint, surplus fossil fuel generated energy

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172 *Ibid* at 21–22.

173 Letter from Kevin Dawson to Tim Grant (30 November 2023) at 4, online: [perma.cc/SBW7-M5MJ] [Dawson Letter].

174 Government of Canada, "*Draft CERs* General Comment Section," *supra* note 39.

175 Crown Investments Corporation of Saskatchewan, "SK Technical Appendix: Clean Electricity Regulations" (2 November 2023) at 14, online (pdf): [perma.cc/9FCA-QX7B].

176 SaskPower, "Response Appendix," *supra* note 41 at 8.

177 Southwest Power Pool is a regional transmission organization regulated by the Federal Energy Regulatory Commission and is responsible for coordinating the reliability of the transmission system and balancing electric supply and demand in its area of the Eastern Interconnection in the US. It has members in 14 states: Arkansas, Colorado, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming (Southwest Power Pool, "SPP Wavelength," online: [perma.cc/9QEX-2C42]; Southwest Power Pool, "Members & Market Participants," online: [perma.cc/E7BH-VMWE]).

178 SaskPower, "Southwest Power Pool Project," online: [perma.cc/K5Y7-THCW].

179 *Canadian Energy Regulator Act*, SC 2019, c 28, s 10 [*CER Act*] (Part 7 states that the Canada Energy Regulator regulates the export of electricity outside of Canada). See also *CER Act*, *ibid*, s 355 (prohibits the export of electricity except in accordance with a permit or licence from the Canada Energy Regulator).

180 Canada, National Energy Board, *Manitoba Hydro-Electric Board's Application Dated 29 May 2015 for Authorization to Export Electricity Pursuant to Section 119.03 of the National Energy Board Act*, Permit EPE-404 (30 July 2015), online: [perma.cc/G9TE-G757].

from Alberta or the US.[181] In its complaint, NorthPoint requests that the Canada Energy Regulator direct Manitoba Hydro to provide FMA to NorthPoint or suspend or revoke Permit EPE-404.[182] At the time of writing, this proceeding was ongoing. However, it nonetheless demonstrates the interprovincial tensions that may arise regarding domestic electricity trade.

Nova Scotia provides another example of canceled or deferred regional co-operation on electricity supply. In the fall of 2023, Nova Scotia abandoned the Atlantic Loop — referred to as the Eastern Clean Energy Initiative — which would have run more than 1,000 kilometres of transmission line from Quebec into New Brunswick and on to Nova Scotia to supply hydro electric energy from Quebec. However, in its fall 2023 Clean Energy Plan, the Government of Nova Scotia indicated that the project was no longer viable in light of ballooning costs, Quebec's confirmation that it does not have firm energy available for sale to meet Nova Scotia's winter peak needs, supply chain challenges, and because "[i]nvesting in our energy resources avoids Nova Scotian's having to spend billions on infrastructure in Quebec and New Brunswick."[183]

RIAS's hopes of encouraging more sharing of electricity among provinces to decarbonize power grids are far from certain. Infrastructure needed for increased domestic trade is lacking, and projects to build new interties or increase intertie capacity are expensive and may compete with other provincial policy objectives. Further, with the prospect of jurisdictions with largely non-emitting generation supply also facing shortages, firm commitments to interprovincial trade may not align with domestic policy objectives. However, where surplus electricity is exported to the US, the added pressure of the *Draft CERs* may subject exports to additional scrutiny and potentially objections.

VI. THE NEED FOR ALIGNMENT BETWEEN GOVERNMENT CLIMATE POLICY AND REGULATORS

The *Draft CERs* and RIAS do not address changes that may be required for provincial regulatory regimes to achieve their 2035 net-zero objectives. In its Interim Report, the Canada Electricity Advisory Council[184] identified that while several provinces and territories have set emissions reduction goals, these have not yet been consistently translated as a specific objective to utility and regulator mandates.[185] The Interim Report stated that aligning regulator and Crown mandates and providing clearer policy direction are essential for: providing greater certainty to markets; enabling clear, optimized, long-term planning; attracting sufficient and competitive capital; and ensuring a reasonably

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181 *NorthPoint Energy Solutions Inc v Manitoba Hydro-Electric Board* (2023), (Affidavit, Jones), online: Canadian Energy Regulator [perma.cc/8CQ7-66F3].

182 *Northpoint Energy Solutions Inc: Complaint Against the Manitoba Hydro-Electric Board Regarding Fair Market Access Required by Electricity Export Permit EPE-404* (9 November 2023), online: Canada Energy Regulator [perma.cc/539R-VGBX].

183 GNS, "Nova Scotia's 2030," *supra* note 124 at 6.

184 The Canada Electricity Advisory Council is an independent, electricity-sector focussed, expert advisory body that provides advice to the Minister of Energy and Natural Resources to accelerate investment, and promote sustainable, affordable, and reliable electricity systems: see e.g. NRC, "Advisory Council," *supra* note 164.

185 *Ibid* at 6.

predictable and timely approvals process.[186] The Interim Report identified "the need to add a vital pillar — the attainment of climate goals — to the existing pillars of reliability and affordability (just and reasonable rates) that currently govern the mandates of utility regulators, system operators, and Crown utilities across Canada."[187] The tension between emission reductions and regulation has been playing out in several jurisdictions in Canada, with varying results.

A recent Ontario Energy Board (OEB) decision is another example of misalignment between government policy and utility regulation. In 2022, Enbridge Gas Inc. (Enbridge) filed an application with OEB seeking approval of proposed changes to the rates Enbridge charges for natural gas distribution, transportation, and storage as of 1 January 2024.[188] OEB raised concerns regarding energy transition in its decision, despite Enbridge's submission of an Energy Transition Plan, on the basis that Enbridge had not met the onus to demonstrate that its proposed capital spending plan was "prudent, and that it has accounted appropriately for the risk arising from the energy transition."[189] OEB found Enbridge's Energy Transition Plan to be unreasonable because it assumed that new housing developments would include gas connections that would remain in service for 40 years.[190] Therefore, OEB determined that for new connections for natural gas service, rather than a 40-year revenue horizon to calculate the upfront capital costs, as historically had been the case, the recovery horizon should be zero years, effectively directing that 100 percent of the connection costs would be paid upfront.[191] In rendering its decision, OEB concluded that energy transition poses a risk that assets used to serve existing and new gas customers would become stranded (that is, retired before the end of their useful life and before all capital costs could be recovered).[192] Enbridge appealed and sought review of OEB's determination, arguing among other things that OEB erred in the decision by not implementing and conflicting with Ontario energy policy, contrary to its statutory objectives.[193] At the time of writing, the appeal was still ongoing.

In response to the OEB decision, the Government of Ontario passed legislation essentially overturning OEB's decision. The *Keeping Energy Costs Down Act, 2024* amends the *Ontario Energy Board Act, 1988* to permit revenue horizons to be set by regulations made under the *Act*.[194] "Revenue horizon" is proposed to be defined as "the number of years of presumed revenue that is used … in determining, (a) the economic feasibly of, (i) a new consumer connection to the natural gas distribution system," and the corresponding "contribution in aid of construction collected from [the] consumer."[195] The amendments also provide authority for regulations to be made that require OEB to "hold a

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186 *Ibid*.
187 *Ibid*.
188 *Enbridge Gas Inc Application for 2024 Rates – Phase 1* (21 December 2023), EB-2022-0200, online: OEB [perma.cc/VG52-J78X].
189 *Ibid* at 20.
190 *Ibid* at 35.
191 *Ibid* at 39.
192 *Ibid* at 50.
193 *Enbridge Gas Inc* (29 January 2024), EB-2024-0078 (Notice of Motion), online: OEB [perma.cc/575J-7FXF].
194 *Keeping Energy Costs Down Act, 2024*, SO 2024, c 10 [*Bill 165*].
195 *Ibid*. Note that *Bill 165* received Royal Ascent on May 16, 2024.

hearing to determine revenue horizons."[196] The provincial government has stated it "intends to immediately introduce regulations to reset the revenue horizon for natural gas connection costs to 40 years."[197]

On the other hand, a 2024 decision by the Ontario Court of Appeal highlights that courts are willing to recognize policy goals as valid regulatory objectives. In *National Steel Car Limited v. Independent Electricity System Operator*,[198] National Steel Car Limited (NSCL) challenged the constitutionality of the electricity charges attributable to the Government of Ontario's feed-in-tariff renewable electricity procurement program (the FIT Program), under which suppliers of renewable energy were paid under long-term, fixed price contracts to "'feed in' energy into Ontario's electricity grid."[199] As a result of the FIT Program, the cost of electricity (in the form of Ontario's "Global Adjustment" charge established by regulation) increased substantially for large industrial users of electricity such as NSCL.[200] NSCL challenged the FIT Program on the basis that it was a tax — not a valid regulatory charge — that was not passed by the legislature. NSCL contended that it served no regulatory purpose other than to provide economic stimulus.[201] The application judge found the FIT Program was a valid regulatory charge related to the regulation of electricity even though it might also provide economic stimulus.[202] The Court of Appeal for Ontario agreed, noting that "[t]he record revealed a Provincial Government working towards the regulatory purpose of increasing and incentivizing renewable electricity generation in Ontario."[203]

Legislation in British Columbia avoids doubt and includes provisions providing direction and alignment between Crown policy and regulation by the British Columbia Utilities Commission (BCUC). Unlike the legislative framework in Ontario, section 46(3.1)(a) of the *Utilities Commission Act* requires that BCUC consider "the applicable of British Columbia's energy objectives" in determining whether to issue a Certificate of Public Convenience and Necessity (CPCN) (enabling rate regulatory cost recovery for a particular undertaking).[204] Section 2 of the *Clean Energy Act* sets out British Columbia's energy objectives, which among other things, include: to reduce GHG emissions, and to encourage the switching from one kind of energy source or use to another that decreases GHG emissions.[205] FortisBC Energy (FortisBC) filed an the application for a CPCN for the Okanagan Capacity Upgrade Project (the Project)[206] on the basis that an increase in its pipeline capacity was necessary due to the increase of the populations of Kelowna, Penticton, and the surrounding Okanagan area.[207] The proposed 30 kilometre natural gas

196 *Ibid*.
197 Government of Ontario, News Release, "Backgrounder: The Keeping Energy Costs Down Act" (22 February 2024), online: [perma.cc/Y6SY-33LW].
198 2024 ONCA 265.
199 *Ibid* at para 1.
200 *Ibid* at para 2.
201 *Ibid* at paras 63–64.
202 *Ibid* at para 66.
203 *Ibid* at para 119.
204 RSBC 1996, c 473, s 46(3.1)(a).
205 SBC 2010, c 22, s 2.
206 *Fortis Energy Inc: Application for Certificate of Public Convenience and Necessity for the Okanagan Capacity Upgrade Project* (22 December 2023), G-361-23 at i, online: BCUC [perma.cc/D6VF-GKU4].
207 *Ibid*.

pipeline and associated facilities were estimated to cost $327.41 million.[208] BCUC denied FortisBC's application.[209] BCUC agreed that demand for natural gas was increasing and the potential shortfall needed to be addressed.[210] However, the Panel noted that FortisBC's forecast did not account for the potential flattening demand as a result of the Province's CleanBC Roadmap, which commits to requiring increasingly stringent emission requirements for new buildings in 2024 and 2027, and for all new buildings to be zero-carbon by 2030.[211] For these reasons, BCUC denied the Project on the basis that public necessity was not proven and the expenditure was too great to justify the Project.[212] Instead, BCUC directed FortisBC to address the potential energy shortfall with short-term mitigation solutions to be filed by 31 July 2024.[213]

The British Columbia legislature's express recognition that BCUC, as a utility regulator, must consider emissions reductions and climate goals in executing its mandate is similar to regulatory changes proposed in Nova Scotia. The NS Task Force Report recommended that the legislature include provisions that clarify utility regulator purpose and objectives to provide "the flexibility it needs to accommodate approaches in rate setting, appropriate to implement government's policy objectives."[214] This recommendation was carried forward to the new *Energy and Regulatory Boards Act*[215] and the *More Access to Energy Act*,[216] created under *ERA 2024*. The *Energy and Regulatory Boards Act* creates the Nova Scotia Energy Board and states that, in setting rates or approving capital projects, the Board must consider, among other things, whether the application supports "sustainable development and sustainable prosperity" and other matters consistent with the purposes of the *More Access to Energy Act*.[217] One of the purposes of the *More Access to Energy Act* is to "support the sustainable development, sustainable prosperity, energy efficiency and greenhouse gas emissions reduction goals of the Province articulated in the *Environmental Goals and Climate Change Reduction Act*."[218]

Given the potential for conflict to arise between traditional utility regulation principles, such as affordability and the lowest cost option and treatment of stranded costs, where regulated entities are making investments or retiring assets early to achieve government policy objectives, clear legislative guidance will be needed to ensure regulatory review and cost recovery related to such actions align with these objectives. Given the potential for lack of alignment between regulators and government policy, it is anticipated that

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208 *Ibid* at 2.
209 *Ibid* at 26.
210 *Ibid*.
211 *Ibid* at i, 16.
212 *Ibid* at ii.
213 *Ibid* at 25.
214 Scott & MacIsaac, *supra* note 127 at 41.
215 *ERA 2024*, *supra* note 131, Schedule A.
216 *Ibid*, Schedule B.
217 *Ibid*, Schedule A, s 6(2)(d).
218 *Ibid*, Schedule B, s 2(e). See also *Environmental Goals and Climate Change Reduction Act*, SNS 2021, c 20 (contains 28 goals that are intended to reduce GHG emissions, grow the green and circular economies, improve the health and sustainability of Nova Scotia's environment, and move to clean and renewable energy).

governments will increasingly be mandating alignment through legislative changes or other legislatively enabled measures.

VII. Reactions and Initiatives to Address Affordability and Customer Choice

Of critical importance to customers is affordability. However, utilities and independent power producers that invest in cleaner sources of electricity generation to facilitate compliance with the *Draft CERs* can be expected to seek a return of and on their investment through customer rates, long-term contracted rates with government, private off-taker agreements, or long-term market prices (as applicable). The federal government has indicated it expects higher incremental increases to residential, commercial, and industrial electricity rates in provinces more reliant on electricity generated using fossil fuel.[219] Multiple parties raised affordability concerns in their submissions on the *Draft CERs*. For example, SaskPower estimates that residential, commercial, and industrial electricity rates in Saskatchewan will more than double by 2035 to cover the costs associated with the *Draft CERs* and federal coal regulations, costing Saskatchewan approximately $40 billion between now and 2035.[220] AESO concluded in its June 2022 Net Zero Emissions Pathways Report that achieving net zero by 2035 would require a 30 to 36 percent ($44 to $52 billion) increase in generation capital investments, generation operating costs, and transmission system revenue requirements from 2022 to 2041.[221] The implications of the *Draft CERs* come at a time when jurisdictions are already grappling with supply adequacy, affordability, and decarbonization issues, and assessing how to allocate the costs of electricity and related infrastructure amongst customers and market participants. In turn, customers are seeking greater flexibility in meeting their electricity demands.

A. Who Pays for What?

In its submissions on the *Draft CERs*, the Government of Alberta submitted that despite the scale of infrastructure needed to achieve a net-zero grid, the federal government has "not identified sufficient funding support to enable the transition,"[222] and called for federal funding commensurate with the *Draft CERs*' impact on Alberta.[223] Similarly, the Government of Saskatchewan submitted that the cost to comply with the *Draft CERs* should be shared by the national tax base rather than exclusively by the provincial rate base.[224]

RIAS highlighted the federal government's commitment of more than $50 billion to help decarbonize the electricity sector, which can help reduce the impact on rates, especially in Atlantic Canada and the Prairies.[225] One such measure the federal government has announced is the proposed clean electricity investment tax credit (the Clean Electricity

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[219] RIAS, *supra* note 18 at 2786.
[220] Government of Saskatchewan, News Release, "Saskatchewan Responds to Unaffordable, Unconstitutional and Unattainable Proposed Federal Clean Electricity Regulations" (21 November 2023), online: [perma.cc/NB4F-CX2B].
[221] AESO, "Net-Zero Report," *supra* note 136 at 6.
[222] AEPA, *Federal Draft CERs*, *supra* note 167 at 17.
[223] *Ibid*.
[224] SaskPower Response Letter, *supra* note 122 at 4.
[225] RIAS, *supra* note 18 at 2812.

ITC). The Clean Electricity ITC would be available to taxable and tax-exempt entities investing in clean energy equipment, such as non-emitting electricity generation, natural gas generation with CCS, electricity storage, and interprovincial transmission infrastructure.[226] Provincial and territorial Crown corporations will only be eligible for the Clean Electricity ITC if they are located in a jurisdiction that publicly commits to work toward a net-zero electricity grid by 2035 and to pass through the value of the Clean Energy ITC to electricity ratepayers to reduce energy bills.[227]

Even absent the impact of the *Draft CERs*, greater government intervention in setting customer rates and electricity pricing can be anticipated in the pursuit of affordability in an era of energy transition and increased electrification. For example, throughout its electricity market review, the Government of Alberta has been keenly focused on affordability. In March 2024, following receipt of the Market Surveillance Administrator and AESO market review reports, the Government of Alberta announced interim regulatory changes to address perceived concerns regarding high electricity prices.[228] The *Market Power Mitigation Regulation*[229] is intended to address economic withholding[230] by implementing a secondary offer cap that limits the offer price[231] of natural gas generating units owned by large generators in the event that net revenues cross a predefined threshold in a given month.[232] The secondary offer cap remains in effect until the first day of the following month and does not apply to generators that use renewable energy sources or any market participant with less than 5 percent of the total maximum capability of energy generating units in Alberta.[233] The regulation does not impose a *price* cap of $125 per MWh. Other suppliers remain free to submit higher offers, and if dispatched, set the system marginal price.

The *Supply Cushion Regulation*[234] is a complementary measure intended to ensure reliability and to curb the exercise of market power where long lead assets are deliberately left off-line during periods of high prices.[235] *SCR* requires AESO to issue directives to certain long lead time assets to come online or stay online when the supply cushion is

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226 Department of Finance Canada, *Budget 2024: Fairness for Every Generation*, Catalogue No 1719-7740 (Ottawa: DFC, 2024) at 186.

227 *Ibid* at 187.

228 Alberta Electric System Operator, "Interim Market Power Mitigation," online: [perma.cc/XFP9-5VDE].

229 *Market Power Mitigation Regulation*, Alta Reg 43/2024 [*MPMR*].

230 Under the current Alberta EOM framework, generators cannot physically withhold available generation capacity from the market and must offer their entire capability to the market. However, economic withholding by pricing energy above marginal cost is permitted. This is intended to allow generators to raise the energy price above marginal cost to ensure they earn the necessary return of and on capital investment: AESO, "REM Report," *supra* note 89 at 58.

231 *MPMR*, *supra* note 229, s 3(6). The offer limit is 25 times the day ahead gas price or $125 per MWh.

232 *Ibid*, ss 1(1)(g), 3(1)–(4), Schedule. The predefined revenue threshold is equivalent to one-sixth of the annualized unavoidable capital investment costs and fixed operating costs of the reference generating unit (*ibid*, s 3(6)). The reference generating unit is premised on combined cycle natural gas generating unit with a net generating capacity of 418 MW (*ibid*, Schedule).

233 *Ibid*, s 4.

234 *Supply Cushion Regulation*, Alta Reg 42/2024 [*SCR*]. Both the *MPMR* and the *SCR* expire in November 2027 unless extended by the Minister.

235 A generator that requires more than one hour to start (synchronize to the interconnected electric system) is allowed to go on long lead time status if it goes off-line. See e.g. Alberta Electric System Operator, "ISO Rules: Part 200 Markets: Division 202 Dispatching the Markets: Section 202.4 Managing Long Lead Time Assets," online (pdf): [perma.cc/8UBQ-FHKU].

calculated to be below a specified threshold of 932 MW.[236] AESO must determine the order of directives according to relative economic merit and physical constraints, and the owner is guaranteed recovery of its costs for operating up to a minimum level.[237] On 19 June 2024, AUC approved AESO's Interim Market Mitigation ISO Rules, which take effect on 1 July 2024, and which will amend sections 202.4, 203.1, 206.1, and 206.3 of the ISO Rules.[238] Whether these measures achieve their intended objectives, and what their impacts on the operation of the EOM and investment in Alberta, remain to be seen.

In addition to their impact on the cost of electricity generated, the *Draft CERs* and the transition to low emitting generation will have other cost impacts that need to be accounted for and funded. Two significant categories of potential costs are the early retirement of emitting generation and significant investments in transmission and distribution infrastructure to connect new generation and support electrification.

RIAS forecasts that only 9 percent of regulated units would retire earlier than otherwise in the absence of the *Draft CERs*, on the assumption that units would implement CCS or operate under the exemption for peaking units.[239] The Government of Saskatchewan has said this forecast is significantly underestimated due to uncertainty regarding cost and availability of CCS for gas-fired units.[240] Regardless of the quantum of early retirements, there may be significant unrecovered costs if generating units are retired before the end of their useful lives.

Consideration of the retirement of coal-fired assets in Nova Scotia by the Nova Scotia Utility and Review Board (NSURB) is illustrative of the potential rate implications of early asset retirement. NS Power expects it will have to retire coal-fired assets and associated infrastructure by 2030 due to its legal decarbonization obligations, prior to fully recovering its investment in these assets or its decommission costs in rates.[241] The undepreciated costs associated with these early retirements "may be as much as $757 million."[242] Seeking approval to accelerate the recovery of depreciation expense (that is, recovery of its remaining capital investment) and decommissioning costs over the years of operation remaining to 2030 "would cause a substantial increase in rates."[243] Therefore, NS Power proposed, and NSURB approved with some changes, the transfer of these costs to a regulatory asset account — the Decarbonization Deferral Account (DDA) — to facilitate rate stability and affordability for customers.[244] NSURB found that the transfer of the costs

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236 *SCR*, *supra* note 234, ss 1(1)(i), 4, 5(1).
237 *Ibid*, ss 5(1), 7(1).
238 *Alberta Electric System Operator: Expedited Approval of Interim Market Power Mitigation Rules* (19 June 2024), 29093-D01-2024, online: AUC [perma.cc/Q6T8-R4XP]. Note that, as of writing this article, the process is still ongoing as the AUC will consider the rules in accordance with section 20.21 of the *Electric Utilities Act* in a separate module within the same proceeding. See also Alberta Electric System Operator, "Interim Market Power Mitigation," online [perma.cc/U3DM-GN65].
239 As discussed above, the *Draft CERs* propose an exemption allowing such units to operate subject to a 150 kilotonnes of CO_2 per year emissions limit and maximum hour duration of 450 hours per year: RIAS, *supra* note 18 at 2772.
240 Crown Investments Corporation of Saskatchewan, *supra* note 175 at 14.
241 *Re Nova Scotia Power Incorporated* (10 April 2024), 2024 NSUARB 67 at paras 1–2, online: NSUARB [perma.cc/VBB2-SFEP].
242 Scott & MacIsaac, *supra* note 127 at 45.
243 *Re Nova Scotia Power Incorporated*, *supra* note 241 at paras 1–2.
244 *Ibid* at paras 3–7.

to the DDA would allow flexibility around the timing of the recovery of the costs,[245] and stated:

> To the extent that costs transferred to the DDA are not offset by governments (to recognize the various policy choices reflected in the laws leading to the premature retirement of assets and the broader social benefits from a decarbonized electricity system), they would be recovered from customers over an undetermined future period.[246]

As is evident from the foregoing, absent government funding and in the pursuit of affordability, regulators may need to consider novel and flexible approaches to address the financial impacts of early retirements and other energy transition costs while ensuring utilities have an opportunity to recover the return of and on their investments.

While the *Draft CERs* highlight the need to invest in new generation, an equally important consideration in an era of increased electrification and changing generation supply mix is the need for operational reliability and investments in transmission and distribution infrastructure. Various stakeholders criticized RIAS as underestimating the cost of implementing the *Draft CERs* because it did not include additional infrastructure costs, such as added grid support (ancillary services cost based on increasing renewables), and other added costs beyond generation (namely, increasing transmission costs).[247]

Accommodating new supply with different attributes and increases in load will require significant investments in expanding and modernizing the electricity system and improving grid resiliency and reliability. In addition, investments are needed to harden assets against severe weather events and other increasing climate related risks such as wildfires, to strengthen system reliability. Although less than projected generation investment, AESO's Net-Zero Report projects that over the 2022 to 2041 timeframe, to achieve net zero by 2035 the incremental cost in utility rates for incremental transmission infrastructure would be between $300 million and $4.3 billion (depending on the generation supply scenario).[248] Similarly, other Canadian jurisdictions have identified the need for significant investments in transmission infrastructure to connect new generation and distribution systems.[249]

The magnitude of these investments may require reconsideration of how such costs are most fairly recovered. In Alberta, the *Transmission Regulation*[250] allocates the majority of the cost of transmission infrastructure to load, which are recovered through the AESO

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245 *Ibid* at para 10.

246 *Ibid* at para 3.

247 Electricity Canada, *Clean Electricity Regulations: Electricity Canada Response* (Ottawa: Electricity Canada, 2 November 2023) at 7; Crown Investments Corporation of Saskatchewan, *supra* note 175 at 14.

248 AESO, "Net-Zero Report," *supra* note 136 at 6.

249 For example, in British Columbia, BC Hydro released its ten year capital plan in January 2024, which includes $21 billion of investments in existing assets and $5 billion to support electrification of the residential, industrial, and transportation sectors: BC Hydro, *Power Pathway: Building B.C.'s Energy Future*, Document No CS-4307 (Vancouver: BC Hydro, January 2024) at 3.

250 *Transmission Regulation*, *supra* note 170.

tariff.[251] Among other things, this was intended to encourage investment in generation with the freedom to locate in areas to maximize access to resources.[252] However, with changes in generation supply mix, this policy is under review. As noted above, the Government of Alberta has released a Green Paper on transmission policy and is reviewing the allocation of transmission costs to introduce locational signals and allocate transmission costs based on causation.[253] Options under consideration include the creation of transmission rights, splitting transmission costs more equally between generation and load, and redefining system costs to allocate more costs to generation during the connection process.[254] AESO has stated that it favours changes to the current cost allocation to require generating unit owners to pay more to reflect the impact on system costs.[255] The allocation of electricity infrastructure costs is a complex issue with no easy answer.[256] Nonetheless, if new allocations for transmission costs are adopted, generating unit owners will need to consider the added cost of transmission in project economics, adding to the complexity of investment decisions at a time when significantly more generation supply will be needed in Alberta.

In adopting legislative changes to address the cost ramifications of the energy transition, governments need to strike an appropriate balance between affordability measures, decarbonization goals, and ensuring regulated utilities maintain an opportunity to earn a fair return. Legislation introduced in Nova Scotia demonstrates the potential pitfalls of impeding a regulator's ability to set just and reasonable rates. In late 2022, the Nova Scotia Legislature passed Bill 212, which amended Nova Scotia's *Public Utilities Act* to restrict rate increases for NS Power.[257] Bill 212 was introduced during NS Power's 2022 to 2024 general rate application proceeding, in which the utility had applied for average smoothed rate increases of 3.6 percent, and was passed prior to NSURB being able to issue its decision on the application.[258] Bill 212 capped net rate increases for NS Power, across all rate classes in 2022, 2023, and 2024 at 1.8 percent with limited exceptions.[259] Following the adoption of Bill 212, NS Power incurred two credit rating downgrades, which NS Power stated had a material impact on the company's ability to finance its operations, provide affordable rates, and invest in capital.[260]

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251 *Ibid*, s 47; *Electric Utilities Act*, SA 2003, c E-5.1, s 30 [*EUA*]. As of writing this article, the costs of local connection of a generator to the transmission system, the cost of line losses, and the generator unit owner's contribution (which is refundable) are the exceptions to the load-pays policy, with all other transmission costs assigned to load.

252 AMAU, *Green Paper*, *supra* note 168 at 16.

253 *Ibid* at 18.

254 *Ibid*.

255 Dawson Letter, *supra* note 173.

256 See e.g. *Alberta Electric System Operator: Bulk, Regional and Modernized Demand Opportunity Service Rate Design Application* (10 November 2022), 26911-D01-2022, online: AUC [perma.cc/KL3V-VESV] (after a lengthy hearing, AUC rejected a rate design proposal by AESO that would have reallocated transmission costs amongst load customers).

257 Bill 212, *An Act to Amend Chapter 380 of the Revised Statutes, 1989, the Public Utilities Act*, 1st Sess, 64th GA, Nova Scotia, 2022; *Public Utilities Act*, RSNS 1989, c 380 [*PUA*].

258 *Re Nova Scotia Power Inc* (2 February 2023), 2023 NSUARB 12 at paras 1–5, online: NSUARB [perma.cc/S8MA-FZ7Y].

259 *PUA*, *supra* note 257, s 64A(3).

260 Scott & MacIsaac, *supra* note 127 at 67.

A. CUSTOMER CHOICE

In addition to affordability considerations that may be implemented directly through government or regulatory action, in the context of the energy transition, consumers are also looking for greater flexibility in meeting their energy needs, whether for policy preference or affordability reasons. In this context, the following are some examples of provincial initiatives aimed at providing industrial consumers with greater choice in sourcing electrical energy.

In Alberta, a particular focus over recent years has been the ability of consumers to self-supply and export electricity, pursuant to which a consumer may generate electricity for its own "Behind the Fence" use and export excess electricity to the grid. After a review by AUC in 2020 and draft legislation being tabled in 2021, on 6 March 2024, the Government of Alberta proclaimed in force the *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act*.[261] Among other things, *ESAA* amends the *Electric Utilities Act* to expressly permit self-supply and export.[262] The amendments to *EUA* exempt the portion of electric energy produced by a generating unit that is "self-supply" from application of *EUA* if the portion of the electricity that is "self-supply" is produced on a property of which a person is the owner or a tenant and is consumed on that same property by that owner or tenant.[263] However, such self-suppliers still may be subject to the payment of rates to recover a "just and reasonable share of the costs associated with the transmission system."[264] While this is a welcome clarification of electric policy in Alberta, as discussed above, if the *Draft CERs* are passed, industrial consumers with large on-site generation will be subject to the prescribed emissions limit if they have net exports of electricity to the grid.

In Saskatchewan, the provincial government's recently announced Renewable Access Service (RAS) demonstrates regulatory change directed at emissions reduction in the electricity sector while facilitating customer choice. SaskPower, a vertically integrated government-owned utility has the exclusive right to supply, transmit, distribute, and sell electricity in Saskatchewan under *The Power Corporation Act*.[265] However, under *PCA*, SaskPower may consent to the supply, transmission, distribution, or sale of electric energy by, or to, another person on any terms and conditions SaskPower deems advisable.[266] RAS permits large commercial and industrial customers to negotiate a Power Purchase Agreement (PPA) with an independent power producer of their choice, and allows a qualifying renewable energy project to be developed for the purpose of supplying clean electricity.[267] SaskPower "operate[s] as the wheeling agent, moving the power from the [independent power producer's] renewable generation site to the customer's site."[268] While

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261 SA 2022, c 8 [*ESAA*].
262 *Ibid*; *EUA*, *supra* note 251.
263 *EUA*, *ibid*, ss 1(1)(vv.1), 2(1)(b)
264 *Ibid*, ss 2(1)(b), 122(2)(b).
265 RSS 1978, c P-19, ss 2, 3(3), 38(1) [*PCA*]. Although the exclusive right is subject to the area not having supply by an entity other than SaskPower prior to 1 January 1958.
266 *Ibid*, s 38(2).
267 SaskPower, "Renewable Access Service," online [perma.cc/FS5U-RBEP].
268 *Ibid*.

limited in scope, RAS provides optionality to consumers in sourcing electricity and may encourage the development of renewable energy generation.

In a similar vein, on 2 November 2023, the Government of Ontario opened a consultation regarding amendments to the global adjustment charge that Ontario's large commercial electricity consumers must pay to fund the cost of non-wholesale market electricity contracts.[269] Prior to any amendments, the global adjustment fees represented a substantial portion of the electricity commodity cost in Ontario.[270] If adopted, the proposed amendments to the global adjustment are designed to expand customer choice by enabling large commercial loads to reduce their global adjustment costs by entering into virtual PPAs with renewable generation facilities — similar to a virtual net metering arrangement — allowing such large loads "to offset their facility's demand in the top five peak hours of a base period" through the qualifying PPA with renewable generation.[271] Eligible technologies for such corporate PPAs may include wind, solar, hydro, and biofuel.[272] The consultation is ongoing with a proposed effective date of 1 May 2025.[273] While still subject to considerable uncertainty as to scope and mechanics, the consultation is a limited step toward allowing access to non-emitting electricity supplies for large customers and providing businesses with more choice to meet their energy needs.

VIII. CONCLUSION

A consistent thread that manifests itself through the various federal and provincial initiatives described in this article is the complexity in balancing competing objectives — the irreversible drive toward electrification, affordability, and reliability — are made more complex in some jurisdictions by the *Draft CERs*' ambition to achieve decarbonization of the energy grid in an abbreviated time frame. The *Draft CERs* are posited on the federal government's conviction that the latter is the more urgent and overriding goal, while the provinces are unsurprisingly focused on the imperative of ensuring reliability and affordability for their residents through the various policies described herein. These complexities are the reality of the diverse supply models and electricity frameworks across the country, which render a one-size-fits-all approach unworkable.

As we have described, supply adequacy is not just a challenge for provinces that rely on emitting sources of generation, as all provinces will need to grow their supply to meet future demand. To meet what is anticipated to be an exponential increase in demand, jurisdictions faced with not only increasing supply but also replacing emitting generation in the proposed timeframe will require unprecedented investment, regulatory efficiency, and political will.

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269 Government of Ontario, "Ontario Regulation 429/04 Amendments Related to the Treatment of Corporate Power Purchase Agreements" (7 May 2024), online: [perma.cc/M5SZ-NMBK] [Government of Ontario, "Regulation 429/04"].

270 Independent Electricity System Operator, "Price Overview: Global Adjustment (GA)," online: [perma.cc/RES5-4EHJ].

271 Government of Ontario, "Regulation 429/04," *supra* note 269.

272 *Ibid*.

273 *Ibid*.

While measures such as the Clean Electricity ITC may attract needed investment by mitigating upfront capital costs to an extent, the *Draft CERs* also come at a time when a critical concern for all stakeholders, and elected governments across the country, is whether this infrastructure can be built in sufficient time and at costs that maintain affordability for consumers. As we note, utilities and independent power producers that invest in cleaner sources of electricity generation to facilitate compliance with the *Draft CERs* can be reasonably expected to seek a return of, and on, their investment. We anticipate the inevitably corresponding rise in rates for residential, commercial, and industrial consumers to prompt greater government intervention in electricity pricing.

If promulgated in their current form, the *Draft CERs* appear poised to collide with provincial policies — such as those in Saskatchewan and Alberta — that have declared a current intent to continue to rely on natural gas generation. Leaving aside whether the federal government has the authority to regulate electricity emissions as contemplated by the *Draft CERs*, federal policy should embed sufficient flexibility to accommodate provincial differences. The Canadian electricity sector is in a state of flux, and federal and provincial policies will continue to play a pivotal role in shaping the future of generation investments and the pace of increased electricity demand. While many provinces are grappling with the same challenge — the complexity of balancing the goals of sustainable, affordable, and reliable electricity — solutions will necessarily vary by jurisdiction and resist a one-size-fits-all approach. However, one commonality is that adherence to the status quo will not be sufficient. Regulators and governments will need to adopt novel and flexible approaches and reconcile these occasionally competing demands to deliver a balanced, realistic, and well-designed roadmap for the electricity sector.