Pembina Institute response to the proposed frame for the Clean Electricity Regulations

Submitted to Environment and Climate Change Canada

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1. Summary

The Pembina Institute welcomes Environment and Climate Change Canada's *Proposed Frame for the Clean Electricity Regulations*[1] as a tangible step towards Canada implementing its commitment to a net-zero grid by 2035. This document is the Institute's response to the proposed frame.

As outlined in our report on *Achieving a Net-Zero Canadian Electricity Grid by 2035* (July 2022),[2] it is crucial that Canada achieves a net-zero grid by 2035 in order to facilitate the full decarbonization of the rest of the economy by 2050, enable grid reliability and resilience, ensure affordability of energy for consumers, create jobs and economic development opportunities, and address historic inequities in the energy system.

The government's *Proposed Frame* provides an overall structure that could deliver a net-zero grid by 2035, if certain design elements and fundamental assumptions are addressed to achieve that goal. In this report, we articulate our reactions to various elements of the proposed frame, and summarize our main reactions below:

CER context and outcomes

- The CER must achieve a **credible net-zero grid by 2035**, which means electricity generation that is predominantly non-emitting and any residual emissions are accounted for with credible offsets.
- An **ambitious and stringent CER** is also needed to ensure that a strong signal is sent to encourage investments in clean energy in the electricity sector. Every additional compromise to the stringency of the CER weakens the clarity of this signal.
- A **net-zero grid can improve reliability and affordability** of electricity for consumers. Any flexibilities introduced to the design with the issues of affordability and reliability in mind should be re-assessed in light of the economic competitiveness of and grid services provided by non-emitting electricity assets.
- We understand that there will be specific **short-term implementation challenges** in certain regions. These challenges should be appropriately addressed — and the opportunities in clean energy taken advantage of — through appropriate **federal and**

[1] Environment and Climate Change Canada, *Proposed Frame for the Clean Electricity Regulations,* July 2022. https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/publications/proposed-frame-clean-electricity-regulations.html

[2] Binnu Jeyakumar, *Achieving a Net-Zero Canadian Electricity Grid by 2035*, July 2022. https://www.pembina.org/pub/achieving-net-zero-canadian-electricity-grid-2035

provincial measures outside the CER, rather than by introducing flexibilities into the CER and thereby reducing its efficacy not only in reducing emissions but also in encouraging new investments in clean energy.

CER design elements

- The **CER must ensure that any electricity emissions in 2035 and beyond are addressed with credible, verifiable, additional and permanent offsets**, in order to achieve a truly net-zero grid by 2035 that is credible to investors, Canadian citizens, companies with ESG goals, civil society, and the international community.
- The **CER must include interim targets, and must be applicable to new units at an earlier point**, to prevent the creation of additional stranded assets in the future.
- **All electricity emissions from cogeneration and behind-the-fence generation must be subject to the CER.**
- **Remote communities and territorial grids must be included in the CER** to ensure they are included in efforts to decarbonize Canada's electricity generation. The recommendations related to remote communities and territorial grids are a working proposal that the Pembina Institute is continuing to engage with Indigenous communities, organizations, and rightsholders to finalize.

2. CER principles and general flexibilities

The Pembina Institute agrees with the context of the proposed frame that characterizes the CER as "part of a suite of federal measures to move Canada's electricity sector to net-zero as an enabler for broader decarbonization of the economy." What sets it apart from the other measures, such as carbon pricing and investment tax credits, is that it has the potential to provide a high degree of regulatory certainty to investors, industry, and communities. It can also provide powerful reassurance to consumers and that the electricity they consume is getting cleaner each year, and from 2035 onwards will not add any more greenhouse gas (GHG) emissions to our atmosphere.

Regulatory certainty is crucial for achieving efficient use of capital and achieving net-zero in an affordable manner, and providing the clear investment signal for industrial and commercial consumers who need net-zero electricity supply. In this way, the CER is a critical element of the government's aforementioned suite of measures. Unnecessary flexibilities and accommodations within it would undermine the CER's vital role in creating certainty.

2.1. Principles for an effective CER

While there may be a few different design pathways for the CER, the effectiveness of the CER must be measured by whether the regulations:

- Deliver a credible net-zero grid by 2035 that is nearly non-emitting and for which any residual emissions are fully offset with credible offsets that are verifiable, additional, and permanent.
- Send an immediate signal that prevents investment in emitting electricity generation assets, and encourages investment in zero- or negative-emissions electricity.
- Generate early and deep GHG reductions, rather than relying on greater reductions closer to 2035 (as the latter approach would increase political and stranded asset risks).
- Secure cost-effective GHG reductions.
- Protect energy affordability and access to electricity for consumers.
- Provide early signals for credible sources of offsets — such as direct air capture — to support their establishment in advance of 2035.

2.2. CER flexibilities and addressing reliability, affordability, and investment concerns

The proposed frame has some core flexibilities built in:

- The emissions intensity standard is technology-agnostic and allows for various technologies to be used including co-firing, fuel switching and installing carbon capture
- Facilities can employ financial / non-physical mechanisms to negate emissions below the regulated standard (i.e. in order to reach net-zero).

The Pembina Institute supports these flexibilities, except — as explained in Section 3.2.3 — we support only credible offsets as the mechanism to meet net-zero in 2035 and beyond.

In addition to the above, the frame also introduces several other flexibilities "to support affordability and reliability," and — as mentioned during the engagement sessions — to provide confidence that the Government of Canada is a predictable regulator. Flexibilities for these issues should only be provided when they are necessary, when they do not materially compromise the emissions outcomes for a 2035 net-zero grid, and when alternative supports to enable strict compliance are not practical. The evolving trends in the electricity sector and energy policies should also be taken into account when considering flexibilities to support the following issues:

1. Affordability

In the electricity sector, non-emitting options such as wind and solar are already cheaper than emitting assets. For example, in most of Europe and the U.S. it is now cheaper to build wind and solar than to continue to operate existing gas plants.[3] In addition, the rising carbon price and increased stringency of industrial carbon pricing systems will accentuate the competitive advantage of non-emitting power in the years ahead. As recent steep increases in natural gas prices have brought into focus, consumers can suffer from the price volatility of an electricity grid that is tied to global fossil fuel markets, whereas a grid that is less reliant on gas-fired generation will result in improved stability for consumer bills.

In addition, the commissioning of new emitting assets that will ultimately be incompatible with a net-zero grid creates increased risk of avoidable stranded assets. This would include the incompatible generating asset itself and the grid infrastructure necessary to connect that generation, both of which could result in costs to taxpayers and ratepayers.

[3] Carbon Tracker, *Put gas on standby*, October 2021. https://carbontracker.org/reports/put-gas-on-standby/

Capital investments will be required for the grid transition, as well as to replace ageing infrastructure and generation assets. These costs are best supported through federal programs, particularly for harder-to-decarbonize provinces. As the Inflation Reduction Act in the U.S. shows, there is a need for federal investments through consumer tax credits, rebate programs, production tax credits, investment tax credits, etc.[4]

So, by and large, the net-zero grid will increase affordability, and short-term capital investments should be supported through other federal programs, rather than by diluting the CER.

2. Reliability

A successful net-zero grid will be able to provide reliable electricity where and when it is needed, while also being resilient to disruptions, especially those caused by the increasing frequency of extreme weather events. The technological pathways to a net-zero grid, such as diversifying the generation mix, investing in energy efficiency, modernizing the grid, and enabling demand-side management, will help improve grid flexibility and reliability.[5] Many of these technologies, such as battery storage, are particularly suited to provide the level of flexibility and responsiveness required by a grid that supports significantly electrified energy end-uses, such as electric vehicles and electric building heating. The Pembina Institute's analysis shows that a clean energy portfolio consisting of renewables, storage, demand-side management and energy efficiency can provide the same energy services as gas power plants in Alberta[6] and Atlantic Canada[7], while being cheaper.

Some of the most cost-effective solutions to improve reliability — such as transmission interties — are complex undertakings that might take several years to complete. Assuming the immediate actions necessary to enable their development is taken, these essential solutions can be ready for 2035. In the interim, other technologies — including gas power plants — can provide reliability.

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[4] Public Broadcasting Service, *What the Inflation Reduction Act does for green energy*, August 2022. https://www.pbs.org/newshour/science/what-the-inflation-reduction-act-does-for-green-energy

[5] Dylan Clark and Anna Kanduth, Enhancing the resilience of Canadian electricity systems for a net zero future (Canadian Institute for Climate Choices, 2021), 3. https://climatechoices.ca/wp-content/uploads/2022/02/Resiliencyscoping-paper-ENGLISH-Final.pdf

[6] Jan Gorski and Binnu Jeyakumar, *Reliable, affordable: The economic case for scaling up clean energy portfolios* (Pembina Institute, 2019). https://www.pembina.org/pub/reliable-affordable-economic-case-scaling-clean-energy-portfolios

[7] Jan Gorski and Binnu Jeyakumar, *Towards a Clean Atlantic Grid: Clean energy technologies for reliable, affordable electricity generation in New Brunswick and Nova Scotia* (Pembina Institute, 2022). https://www.pembina.org/pub/towards-clean-atlantic-grid

So, in specific jurisdictions where no clear alternatives are immediately available before 2035, the end of prescribed life flexibility might allow some emitting generation to bolster reliability; however, these facilities should be utilized sparingly and only when absolutely necessary.

However, flexibilities in or after 2035 that allow emitting assets to continue unabated merely because the necessary non-emitting alternatives are not already in place are unjustifiable. Recent history — such as the dialogue around coal phase-out as recently as 2015 — demonstrates that cost-effective alternatives develop quickly once the clear regulatory expectations are set. Once the goal of a 2030 coal phase-out was clearly set, cost-effective alternatives advanced very quickly, with many conversion commitments announced in 2018 and 2019. The same can be expected over the dozen years between now and 2035, if clear regulatory requirements are in place. However, flexibilities that dilute this clear regulatory signal will undermine the investment necessary to achieve the intended result in 2035. In this way, watered-down stringency can be a self-fulfilling prophecy: accommodating ongoing, high-emitting, unabated thermal generation would be likely to impede investment in abated or non-emitting alternatives including renewables and transmission interties.

3. Protecting investments in the electricity sector

In discussing the need for an End of Prescribed Life, ECCC has expressed the need to extract value from existing assets and to be a predictable regulator to industry. While extracting value from existing assets can be economically efficient, it must be reassessed in cases where new generation might be cheaper than operating existing assets. However, the need to protect these investments must also be balanced with the need to encourage clean energy investments in the electricity grid and not have them edged out by unnecessary accommodations for recent, unabated, emitting assets.

There can be limited application of End of Prescribed Life to investments made before announcements regarding decarbonizing the grid (for example, Canada's 2017 commitment to a 90% non-emitting electricity by 2030, Canada's 2021 commitment to a net-zero grid by 2035, etc.). New investments made since these clear signals, however, do not warrant accommodations: they were not made with a reasonable investment expectation to continue unabated until their capital is recovered.

With the above principles and perspectives on flexibilities and related issues in mind, the Pembina Institute provides the following analysis and recommendations regarding the proposed frame for the Clean Electricity Regulations.

3. Response to “Proposed Key Components of the CER”

This section responds to the proposed frame’s key components. It accepts the core structure of the frame, as the Pembina Institute believes this structure can still deliver a net-zero grid by 2035. Specific recommendations are provided where elements of the structure or yet-to-be determined details need to be resolved to ensure an effective CER. Many of these recommendations need to be adapted to the unique circumstances of remote communities and Territorial grids; the Pembina Institute is continuing to engage with Indigenous communities, organizations, and rightsholders to finalize.

3.1. Response to “Scope of application”

The Pembina Institute supports the first two of the three criteria to determine the scope of electricity generating units that would be subject to the CER: combustion of fossil fuel for generating electricity and a minimum megawatt (MW) threshold capacity. However, we would recommend that the third criteria scope be expanded beyond units that offer electricity for sale onto a regulated electricity system.

3.1.1. Minimum generation capacity threshold

We recommend that **all units with capacity above 5 MW be subject to the CER.**

A facility capacity under 5 MW is a reasonable limit for small-scale generation that does not have substantive impacts on the electricity sector emissions. Facilities under 5 MW are already commonly included under own-use exemptions to provincial electricity regulatory frameworks, such as Alberta’s micro-generation framework.[8] A 5 MW threshold also exempts small generators who may have limited commercial alternatives available.

3.1.2. Electricity sale to regulated electricity system/NERC

The **CER should apply to all electricity generating facilities in Canada above a 5MW threshold, including cogeneration facilities and behind-the-fence generation.**

[8] Government of Alberta, Micro-generation. https://www.alberta.ca/micro-generation.aspx

The exemption for cogeneration and behind-the-fence generation significantly diminishes the emissions reductions from the proposed regulations. Cogeneration and behind-the-fence generation make up a large portion of electricity generation in heavy-emitting provinces; in Alberta, for instance, cogeneration makes up 28% of the province's total electricity generation.[9] Total cogeneration emissions in Alberta amount to approximately 19 Mt, most of which remains behind the fence[10] and would not be subject to the draft CER. The current approach to address emissions exclusively from electricity that is sold to the grid would only capture 31% of cogeneration electricity production. Further, the draft regulations fail to capture 43% of total gas-fired generation in Alberta with this omission (Figure 1).

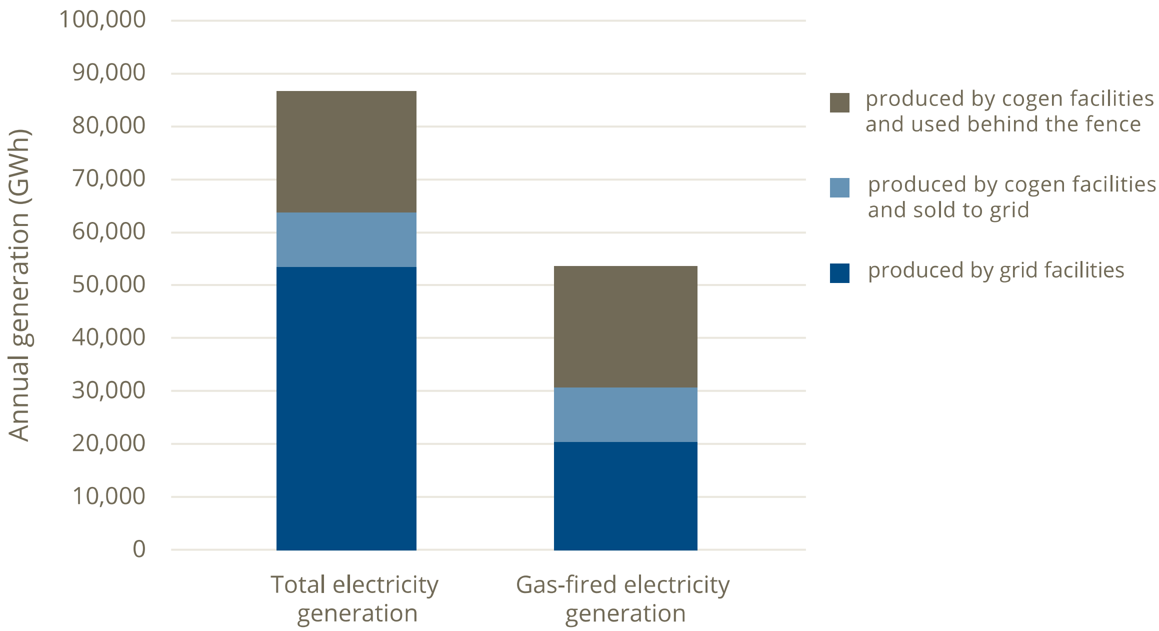

Figure 1. Cogeneration (sold to grid or used behind the fence) as share of total generation and of gas-fired generation in Alberta, 2021

Source: Alberta Utilities Commission[11], Alberta Electric System Operator[12]

Omitting cogeneration and behind-the-fence generation from the regulations would represent a substantial subsidy for these facilities and unfairly disadvantage other generation facilities,

[9]AESO Market Statistics Report. 2022. https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/

[10] Alberta Oil Sands Greenhouse Gas Emission Intensity Analysis. . https://open.alberta.ca/opendata/alberta-oil-sands-greenhouse-gas-emission-intensity-analysis

[11] AUC, "Annual electricity data." https://www.auc.ab.ca/annual-electricity-data/

[12] AESO, "Annual market statistics reports." https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/

which could also encourage grid defection. In order for the net-zero grid of 2035 to support electrification of other sectors cost-effectively, as much generation as possible should be connected to the grid and large customers should not be encouraged to take their load behind their fence.

An alternative approach would be to recognize that emissions from cogeneration facilities are assignable to an electricity product and a non-electricity product. What relevantly distinguishes these facilities is not that they produce electricity for self-consumption (indeed, electricity is also consumed on-site by any type of thermal generator, for which emissions are not excluded from those generators' intensities subject to CER), but rather that they produce more than just electricity and should not have all their emissions factored into the CER.

3.2. Response to "Proposed emissions standard"

3.2.1. Value of physical emissions standard

The physical emissions standard in 2035 should be that of a best-in-class abated gas facility. We recommend a **maximum value of 37 tCO_2e/GWh** based on the best-in-class operational gas facility in Canada and a carbon capture rate of 90%.

At the time of writing, the "good-as-best-gas" emissions intensity benchmark used in Alberta's TIER and the federal OBPS industrial carbon pricing systems are both set at 370 tCO_2e/GWh.[13,14] This represents the best operational natural gas combined cycle (NGCC) facility.[15]

However, there are no operational abated gas facilities in Canada. A 90% stack-level carbon emission capture rate is typically used as the standard for a power plant and was the reported capture rate for the only abated thermal power plant in Canada, Boundary Dam — although this facility operates well below this value for operational stability at just 65%.[16] New innovations may further improve the performance of abated gas generators over the next decade:

[13] Government of Alberta, *Technology Innovation and Emissions Reduction Regulation* (2019), Schedule 2 High-performance Benchmarks. https://www.qp.alberta.ca/570.cfm?frm_isbn=9780779818501&search_by=link. Note: "good-as-best-gas" is described in Government of Alberta, *TIER Regulation Fact Sheet* (2020). https://www.alberta.ca/assets/documents/ep-fact-sheet-tier-regulation.pdf

[14] Government of Canada, *Output-Based Pricing System Regulations* (2019), Schedule 1. https://laws-lois.justice.gc.ca/eng/regulations/SOR-2019-266/index.html

[15] Government of Alberta, *Technology Innovation and Emissions Reduction Review: Discussion Document* (2022), 7. https://www.alberta.ca/assets/documents/aep-technology-innovation-and-emissions-reduction-review-discussion-document.pdf

[16] Saskatoon StarPhoenix, *Saskatchewan carbon capture stumbles on 2021 targets* (2022). https://thestarphoenix.com/news/local-news/saskatchewan-carbon-capture-stumbles-on-2021-targets

- A U.S. demonstration project stably captured just over 92% of its emissions over three years.[17]
- The Capital Power Genesee 1 and 2 projects have announced an emission intensity of 350 tCO_2e/GWh[18] before a carbon capture rate of 95%.[19]

These developments indicate that a physical standard of 37 tCO_2e/GWh should be more than achievable by new generating facilities.

3.2.2. Period of time and level of generation for measurement of emissions intensity

We recommend emissions intensity reporting take place on an **annual basis,** as was required by the Coal Regulation[20] (Schedule 4), the Gas Regulation[21], the federal OBPS[22] and Alberta's TIER[23] industrial carbon pricing systems.

Reporting should be completed at a **unit level**, which provides the most accurate representation of emissions and as was required in the Coal and Gas regulations. However, facility-level compliance might be required in some circumstances, particularly where multiple units share a flue gas exhaust stack.

The proposed frame considers the possibility of fleet-level flexibility. This approach introduces ambiguity and dilutes the signal for an early shift to non-emitting sources. Given that the final net-emissions outcome standard must be zero, and that negative-emissions generation options are likely to be limited, there may not be much utility in establishing a framework for fleet-

[17] Greg Kennedy, *W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project (Final Technical Report)* (2020 . https://doi.org/10.2172/1608572.

[18] Capital Power, "Capital Power accelerating plans towards a low carbon future," media release, December 3, 2020. https://www.capitalpower.com/media/media_releases/capital-power-accelerating-plans-towards-a-low-carbon-future/. Note: this facility is under construction and operational performance values may vary. An earlier 2020 information package lists 360 tCO_2e/GWh. (Capital Power, *Repowering Genesee 1 & Genesee 2.* https://www.capitalpower.com/wp-content/uploads/2020/09/Project-Specific-Information-Package-Genesee-Units-1-and-2-Repowering-.pdf)

[19] Capital Power, *Capital Power advances carbon capture project at Genesee* (2022). https://www.capitalpower.com/media/media_releases/capital-power-advances-carbon-capture-project-at-genesee/

[20] Government of Canada, *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* (2012), Section 15. https://laws-lois.justice.gc.ca/eng/regulations/SOR-2012-167/index.html

[21] Government of Canada, *Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity* (2018), Section 21. https://laws-lois.justice.gc.ca/eng/regulations/SOR-2018-261/index.html

[22] Government of Canada, *Output-based Pricing Regulations* (2019), Section 11 Annual Report. https://laws-lois.justice.gc.ca/eng/regulations/SOR-2019-266/

[23] *Technology Innovation and Emissions Reduction Regulation*, Section 15.

level flexibility. The different technologies being deployed at different facilities and the varying vintage of the facilities require that the emissions be monitored at the facility level to provide the most accurate analysis of changing emissions. We recommend **not including fleet-level compliance in the design of the regulation.**

3.2.3. Mechanisms for achieving net-zero

For a net-zero grid in 2035 and beyond, the only mechanism for achieving net-zero by definition is credible offsets. These offsets must be verifiable, additional and permanent.[24]

The regulation should include intermediate standards that ramp up in applicability and stringency of compliance mechanisms available. Some flexibility may be allowed ahead of 2035 for facilities to use credits to meet the emissions standard or to achieve net-zero.

A financial compliance mechanism, such as carbon pricing, if not directly linked to credible offsets on a tonne-for-tonne basis,[25] will not deliver a truly net-zero grid. While the Pembina Institute still recommends that the electricity sector be exposed to the full carbon price, the carbon pricing mechanism cannot be relied upon to achieve net-zero emissions. It is understood, however, that if a facility purchases offsets for all its emissions, it will not have to pay any carbon price as its effective emissions are zero.

For greater clarity, by 2035, for Canada to claim to have achieved a net-zero electricity grid, all emitting electricity generation facilities — regardless of whether they have been subject to a physical emissions standard (due to delayed applicability for existing generation) — must offset all their emissions.

3.3. Response to “To support affordability and reliability while achieving net zero, the following approaches are proposed”

As explained in Section 2.2, the Pembina Institute does not agree with some of the fundamental assumptions that raise concerns around reliability and affordability, and recommends that most short-term issues be addressed through measures outside the CER that are designed specifically to meet the needs of the jurisdictions that are impacted, rather than

[24] University of Oxford, *The Oxford Principles for Net Zero Aligned Carbon Offsetting* (2020), 5. https://www.smithschool.ox.ac.uk/sites/default/files/2022-01/Oxford-Offsetting-Principles-2020.pdf

[25] Tonne-for-tonne basis: one tonne of compliance purchased through the financial mechanism must be linked directly to procuring a tonne of credible and verifiable emissions offset.

addressing them through adding too many flexibilities to the CER. For the three approaches listed in this section, we recommend the following (explained further in subsequent sections):

- The proposed frame states that unabated natural gas would be allowed during emergency circumstances. Gas facilities that do not meet the physical emissions standard can operate during emergency circumstances, but must purchase offsets.
- The proposed frame states that existing units that have reached their end of prescribed life (EoPL) could continue to generate electricity without meeting the physical standard, with limitations on total emissions and operating hours. **To be clear, existing units that have reached their End of Prescribed Life must — at a minimum — net their emissions to zero through offsets.**

3.4. Response to "Proposed implementation approach and associated dates"

3.4.1. New units

The emissions standard should apply to new units, which we defined as those that are commissioned on or after January 1, 2024.

As stated in the CES Discussion paper, "[s]ending a clear regulatory signal now should discourage further investments in assets that could become stranded in the years to come by this inevitable transition." As such, this immediate intensity standard will provide a clear, unambiguous signal against new, unabated gas-fired generation that will not be net-zero compliant. This will immediately and decisively mitigate against the risk of stranded assets, and subsequently avoid ratepayer costs for infrastructure that would be required to connect these net-zero non-compliant assets. Without this immediate signal, ratepayers would be at elevated risk of stranded infrastructure under a 2035 net-zero requirement and additional capital deployment would be necessary for replacement generation and grid infrastructure.

The exemption from the intensity standard of existing facilities — defined as those that are commissioned on or before December 31, 2023 — provides a generous construction timeline after the federal government announced the net-zero 2035 electricity grid commitment in November 2021, to accommodate projects that had already started construction by the time of that clear policy announcement.

A standard that is not implemented until 2035 would be subject to potential policy and political change, and would thereby create a weaker investment signal for non-emitting generation. Prospective financial backers for those non-emitting investments would have to discount the likelihood of the standard's ultimate implementation and success, unless effective implementation of interim standards can accelerate the certainty of the signal.

The Regulations Limiting Carbon Dioxide Emissions from Natural Gas-fired Generation of Electricity, which were finalized in 2018, define new units as units that begin "generating electricity on or after January 1, 2019." When the federal government published the very first GHG emissions standards for coal-fired power facilities in 2012, it allowed three years during which new facilities could be built without being subject to the standards. Ultimately no new facility was built, but this was only because of two reasons that do not apply here: 1) super-critical coal-fired plants have a longer construction timeline than gas-fired facilities; and 2) the Pembina Institute brought litigation against the unprecedented interim regulatory approval of the one unabated unit that did try to slip under the wire, managing to delay the final investment decision for the facility.

Unabated gas assets also run the risk of becoming uncompetitive in a net-zero grid and turning into a stranded asset that may impose costs on taxpayers and ratepayers. This can also lock in capital that could otherwise be deployed for non-emitting sources. This risk can be particularly material in certain provinces:

- In Alberta (Figure 2), there is about 1,820 MW of gas capacity currently under construction, while another 3,322 MW has secured regulatory approval.
- In Saskatchewan (Figure 3), 360 MW of new gas capacity is currently under construction. Meanwhile, one project with nameplate capacity of 370 MW is currently awaiting a decision on construction, anticipated in early 2023. If the project is approved, the construction will be completed by 2028. Additionally, two facilities are undergoing capacity expansion with each facility increasing its capacity by 46 MW.

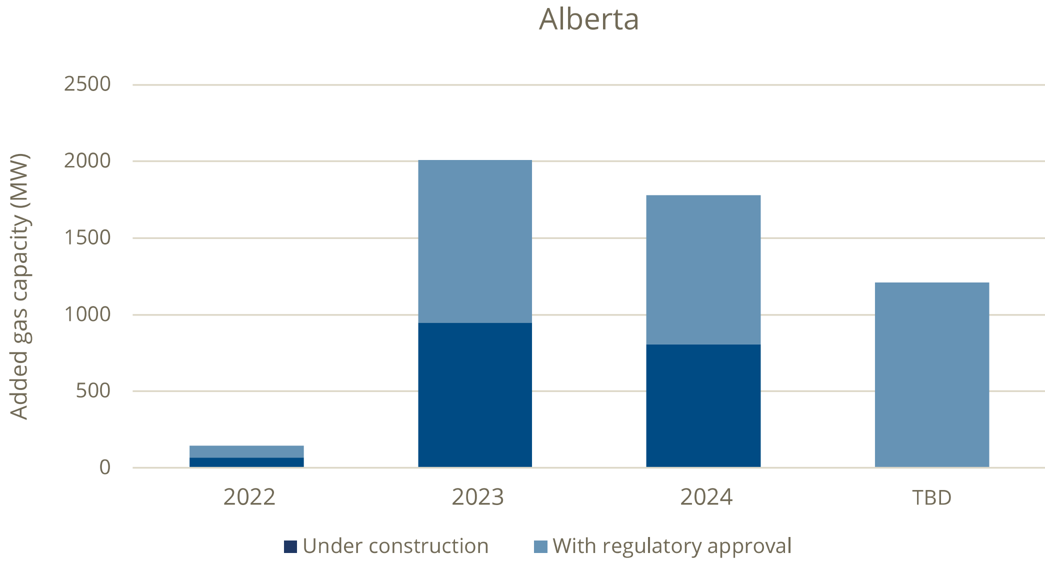

Figure 2. Anticipated gas-fired capacity additions in Alberta, by the published in-service date as of August 2022

Data source: AESO[26]

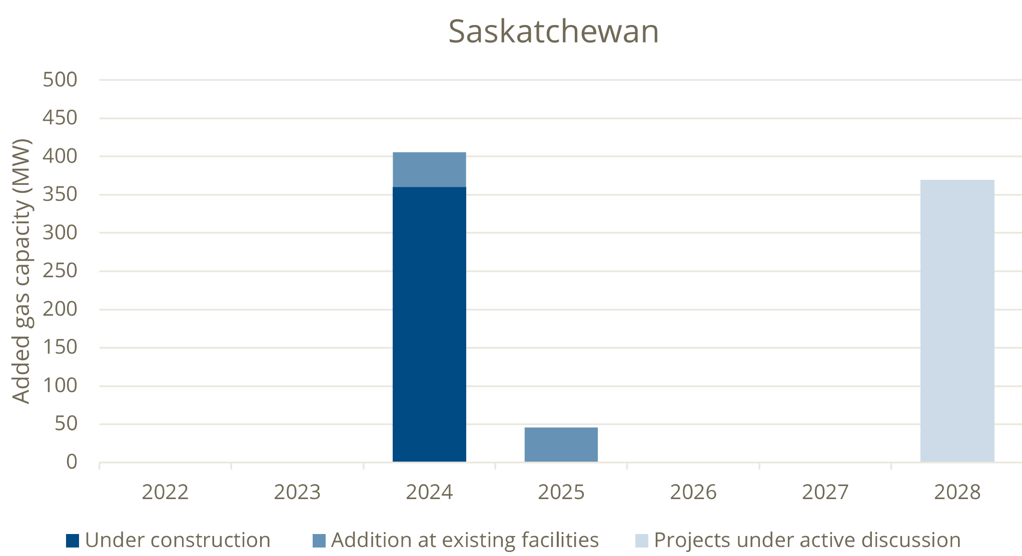

Figure 3. Anticipated gas-fired capacity additions in Saskatchewan

Data source: SaskPower[27]

[26] Alberta Electricity System Operator, *Long-term Adequacy Metrics – May 2022*. https://www.aeso.ca/download/listedfiles/2022_05_LTA.pdf

[27] SaskPower, Potential Lanigan Natural Gas Power Station (n.d.). https://www.saskpower.com/Our-Power-Future/Infrastructure-Projects/Construction-Projects/Current-Projects/Potential-Lanigan-Natural-Gas-Power-Station; SaskPower, Yellowhead Power Station Expansion (n.d.). https://www.saskpower.com/Our-Power-

Policymakers should assume that investors and industry have been aware of the steady acceleration of climate policy in the electricity sector in recent decades (Figure 4 below), and the 2024 deadline should not come as a surprise, nor be legitimately seen as undermining regulatory predictability.

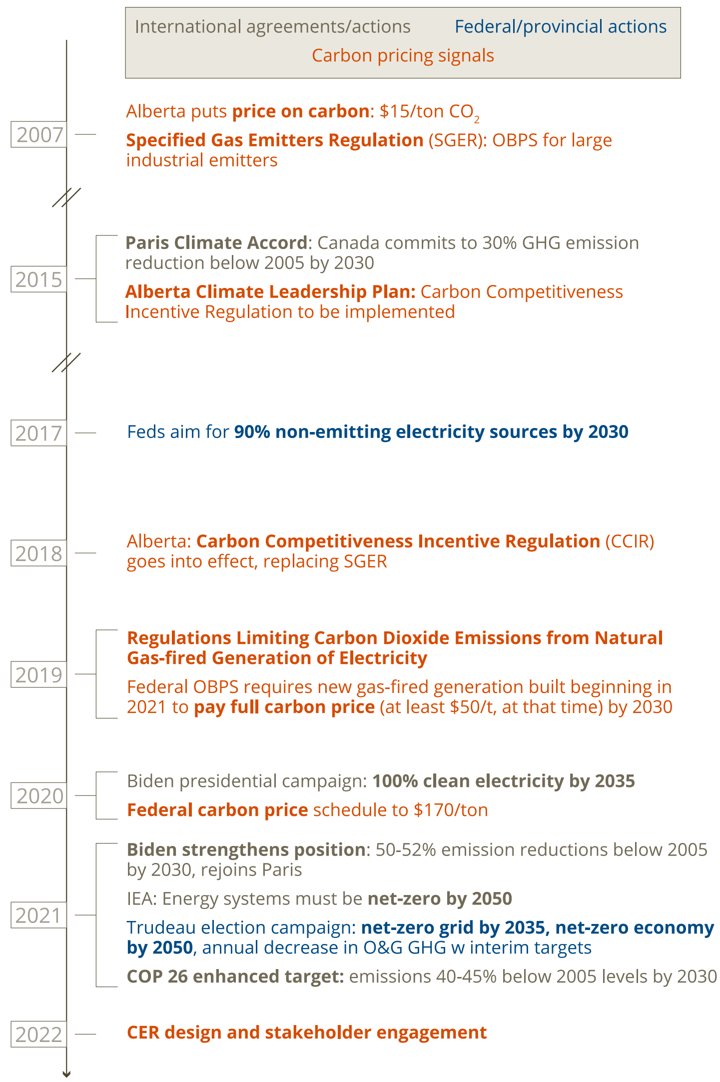

Figure 4. Timeline of energy and climate policies relevant to Canada's electricity sector

As our CER recommendations indicate, the Pembina Institute proposes flexibility mechanisms for new generation to meet the standard ahead of 2035. We propose that **new facilities be allowed to meet the standard through the use of credits until 2035, and offset the**

Future/Infrastructure-Projects/Construction-Projects/Current-Projects/Yellowhead-Power-Station-Expansion; SaskPower, Ermine Power Station Expansion (n.d.). https://www.saskpower.com/Our-Power-Future/Infrastructure-Projects/Construction-Projects/Current-Projects/Ermine-Power-Station-Expansion; SaskPower, Great Plains Power Station (n.d.). https://www.saskpower.com/Our-Power-Future/Infrastructure-Projects/Construction-Projects/Current-Projects/Great-Plains-Power-Station

remaining emissions to zero. Creating immediate demand for the limited class of credible offsets necessary to substantiate a net-zero grid claim will help to foster investment in those offset-generating activities, to ramp up to 2035. This helps to mitigate the risk of insufficient offset availability in 2035 and allays the delay in investment that could result from political risk waiting for an offset signal that is multiple political cycles in the future.

3.4.2. Existing units

Following the discussion in section 3.4.1 above, it follows that **existing units should be units commissioned on or before December 31, 2023.**

We recommend that **the end of prescribed life (EoPL) be defined as no longer than 15 years** from a unit's commissioning date. This stipulation, coupled with the definition of existing units, implies that no existing unit will have an EoPL past 2038. This definition of EoPL strikes a good balance between providing reasonable time to recover capital costs, and ensuring that significant emissions are not left unabated in the electricity system in 2035.[28]

As an illustration, Figure 5 below estimates the amount of gas capacity that will have an exemption until after 2035 based on various EoPL definitions. For context, in 2035, Canada is projected to have a total gas capacity of 34,986 MW, under the current policy scenario.[29]

[28] Carvalho, Rexon, Eric Hittinger, and Eric Williams. Payback of natural gas turbines: A retrospective analysis with implications for decarbonizing grids. Utilities Policy 73 (2021): 101307.

[29] Canada Energy Regulator, Canada's *Energy Future 2021: Energy Supply and Demand Projections to 2050*. https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

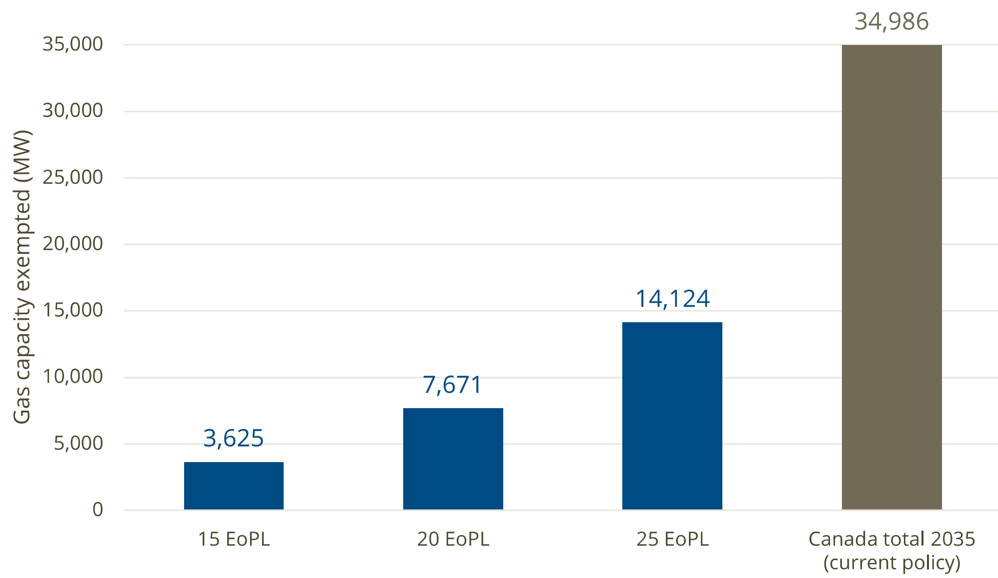

Figure 5. Gas capacity exempted in AB, SK, and ON, until after 2035 under various EoPL definitions

Data sources: Various[30]

To provide some flexibility to existing units while maintaining the progress towards a net-zero grid, we recommend that **by 2030, existing units after reaching their EoPL be required to**

[30] Data source for the EoPL graph are as following: Alberta data: Coordinating Council, 2021-04-30 WECC Resource List. https://www.wecc.org/Reliability/2021-04-30%20WECC%20Resource%20List.xlsx; Alberta Electricity System Operator, SH1 Sheerness#1 and SH2 Sheerness #2 – Change in Fuel Type Notice (n.d.). https://www.aeso.ca/market/market-updates/2021/sh1-sheerness-1-and-sh2-sheerness-2-change-in-fuel-type-notice/; Alberta Electricity System operator, New Asset NPC3 Elmworth (NPC3) Notice (n.d.). https://www.aeso.ca/market/market-updates/2022/new-asset-npc3-elmworth-npc3-notice/; Alberta Electricity System operator, BR4 Battle River #4 – Change in Fuel Type Notice (n.d.). https://www.aeso.ca/market/market-updates/2022/br4-battle-river-4-change-in-fuel-type-notice/.

Saskatchewan data: SaskPower, Ermine Power Station (n.d.). SaskPower, Peaking Stations (n.d.). https://web.archive.org/web/20110928030554/http:/www.saskpower.com/about_us/generation_transmission_distribution/peaking_stations.shtml; SaskPower, Yellowhead Power Station Expansion (n.d.). https://www.saskpower.com/Our-Power-Future/Infrastructure-Projects/Construction-Projects/Current-Projects/Yellowhead-Power-Station-Expansion; SaskPower, Great Plains Power Station (n.d.).; SaskPower, Chinook Power Station (n.d.). https://www.saskpower.com/Our-Power-Future/Our-Electricity/Electrical-System/System-Map/Chinook-Power-Station; SaskPower, North Battleford Power Station (n.d.). https://www.saskpower.com/Our-Power-Future/Our-Electricity/Electrical-System/System-Map/North-Battleford-Power-Station; SaskPower, Spy Hill Power Station (n.d.). https://www.saskpower.com/Our-Power-Future/Our-Electricity/Electrical-System/System-Map/Spy-Hill-Power-Station; SaskPower, A Powerful Connection: SaskPower 2015-16 Annual Report (n.d.). https://www.saskpower.com/-/media/SaskPower/About-Us/Reports/Past-Reports/Report-AnnualReport-2015-16.ashx;

Ontario data: Independent Electricity System Operator, IESO Active Generation Contract List [with nameplate capacity] (30 June 2022). *Obtained via email communication from IESO;* Ontario Energy Board, Electricity Generation License EG-2004-0540: Portlands Energy Centre Inc. on behalf of Portlands Energy Centre valid until March 10, 2026. https://www.rds.oeb.ca/CMWebDrawer/Record/210599/File/document

offset all their emissions to achieve net-zero emissions, and existing units prior to their EoPL be required to meet the regulated physical standard through offsets.

There is considerable risk — particularly given political uncertainties — associated with waiting to apply the standard until 2035. Such uncertainty would undermine the investment signal for net-zero-compliant generation, presenting obstacles to financing for those projects. In addition, owners of existing generation that undertake retrofits would risk being out-competed by generation that gambles on policy backsliding in the lead-up to 2035, which will deter low-cost financing for these projects. An interim standard for existing generation will shore up regulatory certainty for retrofit investments.

Moreover, the timeline of 2030 for the interim target corresponds to Canada's commitment to achieve a 90% emissions-free grid by 2030, and the expectation that individual generation facilities support that near-term outcome. Finally, sending a growing demand signal for new offset supply in advance of 2035 will help to ensure that offset development will grow to enable the full offsetting of residual emissions as required in 2035.

3.5. Response to "Proposed requirements for compliance for all emissions below the regulatory limit"

We recommend that **compliance for emissions below the regulatory standard only be allowed via use of offsets and should apply to new units starting in 2024, and to existing units after their EoPL.**

Facilities could comply with the net-zero emissions outcome by purchasing (or otherwise acquiring) and retiring offsets from carbon reduction activities outside of the CER (i.e., from outside the electricity sector) that meet a rigorous threshold of credibility, permanence, verifiability and additionality, or from carbon dioxide removal activities like direct air capture. As explained in section 3.2.3, the mechanism must be credible offsets and not carbon pricing, in order to achieve a truly net-zero emissions grid.

The language in this section of the proposed frame should be clarified to **confirm that units that have yet to reach their EoPL will be required to account for all their emissions** (not just emissions below the regulatory standard) and offset to zero. To substantiate the commitment to net-zero 2035, it is critical to offset all electricity emissions within scope, regardless of the generating unit vintage, without exemption. That overriding requirement needs to be clearly articulated.

3.6. Response to "Potential compliance flexibility"

The proposed frame states that fleet averaging approaches could ease compliance burdens and incentivize renewables. We recommend that **the application of and compliance with the CER should be monitored and enforced at the individual facility level.**

Fleet-level flexibility introduces ambiguity and dilutes the signal for an early shift to non-emitting sources. Given that the final net-outcome standard must be zero, and that negative-emissions generation options are likely to be limited, there may not be much utility in establishing a framework for fleet-level flexibility. The different technologies being deployed at different facilities and the varying vintage of the facilities require that the emissions be monitored at the facility level to provide the most accurate analysis of changing emissions. Unit-level would be the most accurate, but this data may not be available for units that share the same emissions stack.

3.7. Response to "Proposed exemptions from the CER performance for regulated units"

3.7.1. Emergency use

Units being used during emergency circumstances do not need to meet the physical standard, but must purchase offsets to meet net-zero emissions. In addition, the definition of emergency must be precise and truly extraordinary, unforeseen, and irresistible.

Non-emitting technologies — particularly storage technologies — are available for dispatch in emergency situations. Exempting emergency use situations would undermine the signal to deploy these technologies for use in emergencies. Moreover, there is substantial policy loophole risk in the definition of "emergency" that could seriously dilute the effect of the CER and result in an outcome that cannot be credibly termed "net-zero grid".

3.7.2. Remote communities and territorial grids.

Remote communities and territorial grids must be included in the CER to ensure they are included in efforts to decarbonize Canada's electricity generation.

The exemption of remote communities and territorial grids from the CER will result in reduced market signals and funding streams, failing to support a low-carbon economy and ultimately leaving these jurisdictions behind in Canada's clean energy transition. Remote communities can be defined in the context of this response as those without access to the North American electricity grid or natural gas infrastructure.

The regulations however should be adapted to the context and needs of remote communities, which are very distinct from non-remote communities. Appropriate compliance timeframes, funding, and programs are needed to support adoption of this regulation in remote communities to avoid any excessive burdens on remote communities and jurisdictions with potentially limited non-emitting generation options.

We recommend the following changes to include remote and territorial grids in the CER. These recommendations are a working proposal that the Pembina Institute is continuing to engage with Indigenous communities, organizations, and rightsholders to finalize.

1 MW minimum threshold

Remote communities and territorial grids should only be subject to the CER if the total community fossil fuel (typically diesel) generation capacity exceeds a minimum 1 MW threshold. This different standard is to account for the fact that most remote communities have facilities with much smaller capacity than in non-remote communities. As shown in the following Table 1, this threshold would result in 59% of remote communities having to comply with the CER.

Table 1. Proportion of remote communities with total fossil fuel generation capacity within bounds.

Province / Territory	Fossil fuel generation capacity range				
	< 300 kW	300–500 kW	500–800 kW	800 kW–1 MW	>1 MW
AB	0%	33%	0%	0%	67%
BC	42%	4%	8%	8%	38%
MB	0%	0%	0%	0%	100%
NL	10%	5%	14%	10%	62%
NT	18%	9%	15%	6%	53%
NU	0%	0%	4%	8%	88%
ON	13%	7%	3%	17%	60%

QC	0%	0%	9%	9%	83%
SK	100%	0%	0%	0%	0%
YT	35%	0%	5%	15%	45%
All remotes	**22%**	**6%**	**6%**	**7%**	**59%**

Data source: Pembina Institute[31]

A minimum threshold for application of the CER in remote communities is necessary to avoid burdening communities where emitting generation is minimal, even compared to the scale of typical remote community capacity, while still ensuring that the majority of remote jurisdictions are included in efforts to decarbonize Canada's electricity generation. The minimum threshold for remote communities is on a facility rather than individual genset basis to avoid utilities instead choosing to install many small gensets to meet their load.

No exemption for Territories and remote communities

The proposed exemptions from the CER for "units operating in areas not connected to an electricity system regulated by NERC" implicates remote communities and the territories, both of which remain in large part exempt from the federal price on carbon. The Clean Electricity Regulation is a necessary driver to transition off diesel reliance in these jurisdictions, where exemptions make other mechanisms obsolete. The regulation also poses opportunities for the territories to advance their clean economies as market opportunities accelerate to support the implementation of the CER in Canada's provinces. The requirement for units to be regulated by NERC for inclusion in the CER should be removed such that territorial grids and remote communities meeting the minimum generation capacity threshold are subject to the regulation.

Limited flexibility for remote communities

For most remote communities, diesel gensets provide primary power. Gensets must remain operational at the community level so that they can come online in instances of service interruptions due to distribution failures or periods of power unavailability from other generation supply to the community. Transmission interconnections, which can provide balancing capacity in other regions, are extremely uneconomical for these communities as it would require the build out of hundreds of kilometres of infrastructure to service loads

[31] Dave Lovekin et al, *Diesel Reduction Progress in Remote Communities* (Pembina Institute, 2020). https://www.pembina.org/pub/diesel-reduction-progress-remote-communities

generally under a few megawatts. Without these essential diesel generators, energy insecurity risks in remote communities are significant. Many communities are fly-in only and delays for transporting the staff or parts needed to address any system failures could result in extended periods of power unavailability. In extreme cases, extended outages could result in communities having to be temporarily relocated while power is unavailable. For these reasons, diesel generators will remain essential for remote community electricity systems even after high-penetration renewable energy integration is achieved. So we recommend that the **community diesel gensets used to supply power during disruptions should remain exempt from the CER**, i.e. not required to meet the regulatory standard or to offset emissions to zero. However, these diesel generators should only be exempt if they satisfy maximum annual emissions and hours of operation, where the maximum limits are determined for the context of remote communities through engagements with them.

The recommendations outlined in this document must be adapted for territorial grids and remote communities to differ from grid-tied (NERC-regulated) jurisdictions both in terms of timeframe and targets. Remote and territorial jurisdictions are much more sensitive to cost and energy security implications associated with meeting these regulations. Additionally, technical solutions, particularly carbon capture and storage, have limited potential for application in remote communities due to economics and scale of application, restricting avenues to meeting the recommendations outlined for NERC-regulated jurisdictions. Fundamentally, application of the CER by the same means for remote Indigenous communities is contrary to the inherent rights of those impacted, as implicated by the United Nations Declaration on the Rights of Indigenous Peoples and principles of free, prior and informed consent. Further engagement with affected Indigenous rightsholders must be conducted prior to establishing what these adapted recommendations should be.

4. Request for further information

The Pembina Institute has done its best to collate accessible publicly available data and research to inform its positions in this document. However, further information can help us understand the nature of some of the challenges to implementing a stringent CER and the impacts of flexibility mechanisms on GHG emissions reductions. With that in mind, we respectfully request the following data and information from ECCC:

- **Requirement for compliance options under criminal code** – We understand from ECCC that, given the CER will fall under Canada's Criminal Code, there is a duty to demonstrate/assure adequate compliance options. We would appreciate more information from ECCC or the Department of Justice on what the nature of the threshold for adequacy of compliance options is.
- **Availability of offsets –** Given the criticality of offset availability not only for the electricity sector, but also — and more importantly — for harder-to-decarbonize sectors, we ask that ECCC articulate the scope of work and effort required to build and maintain appropriate offset protocols for high-quality credible offsets. In addition, we ask that ECCC provide estimates of the amount of credible offsets currently available, and projected to be available in 2030 and in 2035 — and as a corollary, an estimate of the amount of offsets anticipated to be needed to decarbonize the grid in 2035 and the economy in 2050.
- **Incentives and costs to fossil fuel generation** – There are several programs and regulations related to the electricity sector — some already established, some being reviewed, and some being designed — that will impose various costs and provide various incentives for fossil fuel generation. An analysis of a few plausible scenarios of the net costs to fossil fuel generation will help understand how these programs and regulations could impact investment decisions.
- **Net costs of a net-zero grid** – We appreciate that ECCC is modelling various scenarios to understand the net cost impact of grid decarbonization. We look forward to seeing the results, and request that the analysis avoid some of the common challenges and missteps[32] associated with analyses of this kind by:
  - Scenario modelling the price of natural gas, including the risk of price instability associated with a commodity that is tied to global markets

[32] Nick Schumacher and Binnu Jeyakumar, *Pembina Institute response to AESO Net-Zero Emissions Pathways Report*, July 2022. https://www.pembina.org/pub/pembina-institute-response-aeso-net-zero-emissions-pathways-report

- Representing net cost of emitting generation assets that includes:
  - Assumptions around the availability of government funding for carbon capture and storage (CCS)
  - Impact of rising carbon price
- Updating forecasts for the price of renewables and battery storage
- Conducting cost-benefit analyses of investment in interprovincial transmission, including the potential benefits such investment would have in providing low-carbon power during periods of peak demand in Alberta
- Impact of demand-side measures and energy efficiency
- Modelling of monetization of the value of various grid services provided by non-emitting assets, such as renewables and battery storage