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Pembina Institute response to draft Clean Electricity Regulations

Submitted to Environment and Climate Change Canada

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Summary

The Pembina Institute congratulates Environment and Climate Change Canada for the extensive consultations held over the last year and a half, and for the resulting draft Clean Electricity Regulations (CER).

As Canada joins several other peer countries in implementing its commitment to a net-zero grid by 2035, the CER is a much-needed regulatory tool to attract low-cost financing to the investments that are needed in the grid. As more regions achieve a clean grid, they will benefit from attracting more global capital that is seeking to make net-zero aligned investments. Moreover, the net-zero grid is a precondition for a net-zero economy in 2050.

1.1.1 The affordable, reliable net-zero grid is achievable

Analysis from the Pembina Institute has shown that a net-zero grid can indeed be achieved even in a jurisdiction as difficult to decarbonize as Alberta, in an affordable and reliable manner. This is because of the incredibly low costs of wind, solar and battery storage. While getting to a net-zero grid is not an easy task, we can learn from our experience with phasing out coal, where stakeholders also raised concerns about reliability and affordability, yet we are achieving the coal phase-out milestone early through carbon pricing backstopped by regulatory certainty.

1.1.2 The CER's objectives need to be reconfirmed

We note that the stated objectives of the CER in the draft regulations text are inadequate when compared to Canada's broader electricity strategy as defined in Natural Resources Canada (NRCan)'s *Powering Canada Forward*. While the draft CER no longer aims to achieve a net-zero grid by 2035, it remains a critical tool for decarbonizing our grids, and indeed there is a pathway for the CER, in combination with robust carbon pricing mechanisms, to provide regulatory certainty in support of a 2035 net-zero grid. To this end, the CER along with carbon pricing must achieve the following:

- Significantly reduce emissions in the electricity sector by 2035 while maintaining electricity reliability and affordability
- Incentivize early action in order to reduce emissions and reduce investor risk
- Support netting or negation of the residual emissions on the grid in 2035

1.1.3 Recommendations

The Pembina Institute examined the key elements of the CER taking into consideration reliability arguments that have been brought forth during the consultations to date, affordability of electricity, and the emissions objectives mentioned above. Our analysis included global data as well as data from Alberta, Saskatchewan and Ontario, with a particular focus on grid reliability in Alberta, which has the greatest amount of gas-fired generation. We make the following recommendations for balanced approaches that achieve the purpose of the policy elements and flexibilities while preserving the emissions objectives:

- **The emissions performance standard should be kept at a level that discourages investments in unabated or incrementally abated gas plants;** a weaker standard may be introduced for 2030 and ratcheted down in 2035.
- **The peaker exemption to the physical standard should not exceed 450 hours of operation.** This is to avoid undermining the regulatory signal for emerging non-emitting options, which are able to provide the services of peaker gas plants in most conditions. In Alberta, the 450-hour limit is more than sufficient to meet electricity demand under the most cost-effective net-zero 2035 scenarios, and market changes are already underway that may help address any concerns of the operators of peaker plants around generating adequate revenue (which would have been a challenge even without the CER).
- **The End of Prescribed Life (EoPL) exemption from the emissions performance standard should not exceed 20 years.** A 20-year EoPL still leaves significant unabated gas — and its corresponding emissions — on the grid in 2035. There is no compelling investment expectation justifying an extension of the EoPL beyond 20 years. In Alberta, the peaker exemption is sufficient for reliability.
- **Cogeneration units that have net exports to the grid should be subject to the CER standard.** Most of the cogeneration capacity in Canada is located in Alberta where a different treatment of net exports is firstly unnecessary as any potential reduction in exports will not impact grid reliability. A different treatment would also undermine fair competition by advantaging a very large market participant over other generators.
- **Remote communities and territorial grids must be included in the CER or given the option to opt into the CER** to ensure they are included in efforts to decarbonize Canada's electricity generation. A full exemption of remote communities and territorial grids from the CER will reduce market signals.

- **The CER should require reporting of the emissions, emissions intensity, hours and net-to-grid export at the unit-level on an annual basis, and this data should be publicly available.**
- **At the time of publication of the final CER, the federal government must announce its intention to revise the Output-Based Pricing System (OBPS) to require full pricing of all electricity sector emissions in all provinces to procure tonne-for-tonne negative emissions** for the residual emissions. While we have shown that significant decarbonization will not increase electricity costs, as a proactive measure, the federal government and provinces should commit to ongoing joint work to monitor and ensure electricity affordability is maintained, especially for the most vulnerable consumers.

2. Context and principles for the Clean Electricity Regulations

2.1 Context for net-zero grid in Canada and clean electricity regulations

Canada and its provinces have a lot to gain from achieving a net-zero grid by 2035, which it can do in a reliable and affordable manner. While the Clean Electricity Regulations (CER) alone will not deliver this goal, it is critical that they are designed as an effective emissions reduction tool.

Canada is not alone in committing to a net-zero or clean grid by 2035. Other countries such as the U.S., the U.K., and Germany have also made this commitment. They are driven by the economic, reliability and energy security advantages of a clean grid, and the fact it attracts more investments than a carbon intensive grid. The other compelling factor for them is that a net-zero grid by 2035 in developed countries is a necessary step towards keeping global temperature rise below 1.5°C, as per the International Energy Agency (IEA) and the Intergovernmental Panel on Climate Change (IPCC). Electricity decarbonization is low-hanging fruit, thanks to the readily available low- and non-emitting alternatives; as well, decarbonizing the rest of the economy will require widespread electrification of transportation, buildings, and heating, all of which will rely on a net-zero grid as a precondition.

The different countries already working towards this goal have their own advantages and challenges, and yet most are ahead of Canada in terms of their ability to run their grids on variable renewables. The U.K. for example is on track to be able to run its grid with zero emissions by 2025.[1] Additionally, the IEA's 2023 World Energy Outlook notes that a record-breaking 500 GW of new renewables are set to be added globally in 2023, with more than USD 1 billion a day spent on solar development.[2] It is critical that Canada gets on the trajectory to achieving a credibly net-zero emitting grid by 2035, in

[1] Zero emission operation would start with periods of a minute or two and a time, with the goal of achieving 100% of hours by 2035. (National Grid Electricity System Operator, "A net zero future." https://www.nationalgrideso.com/future-energy)

[2] International Energy Agency, *World Energy Outlook 2023*, 17. https://www.iea.org/reports/world-energy-outlook-2023

order to keep up with our peers, to not lose out on clean energy investments and companies that are seeking clean electricity for their operations, and to take advantage of the energy security, affordability and reliability of a net-zero grid.

Canada's introduction of the draft CER[3] is not unique. The draft Environmental Protection Agency (EPA) regulations to limit power plant emissions were released by the U.S. federal government three months ahead of Canada's CER.

The Canadian federal government has made it clear that the CER will not achieve a net-zero grid on its own. However, it is the only regulatory instrument that can provide certainty to investors, utilities, and communities on the necessary timeline for the transition. This certainty is crucial, particularly to enable the significant investments —– and associated low-cost financing — needed to expand the grid. We need to lock in certainty that low- and non-emitting electricity will be available, affordable and reliable well in advance of the 2050 economy-wide decarbonization that is essential for meeting global climate targets.

It is critical that the CER is stringent enough to reduce emissions significantly, to send a strong, immediate signal to discourage wasted investment in high-emitting generation and to encourage investment in clean energy and the enabling infrastructure.

2.2 The feasibility of an affordable net-zero grid by 2035

Analysis from the Pembina Institute has shown that a net-zero grid can indeed be achieved even in a jurisdiction as difficult to decarbonize as Alberta, in an affordable and reliable manner.

In fact, our *Zeroing In* report shows that significant decarbonization of Alberta's electricity system can be achieved by 2035 (Figure 1), saving the province $22 billion in system costs (Figure 2) and consumers up to $600 per household on their annual electricity costs. Further, we found that a decarbonized grid would unlock significant economic benefit through net exports of electricity to British Columbia, Montana and Saskatchewan (Figure 3). Additionally, provinces with low carbon grids have demonstrated success using them to attract net-zero aligned businesses and investments, unlocking even more economic benefits.

[3] Government of Canada, "Clean Electricity Regulations," *Canada Gazette Part I,* 157, no. 33, August 19, 2023, 2709. https://www.gazette.gc.ca/rp-pr/p1/2023/2023-08-19/pdf/g1-15733.pdf

These results are supported by similar studies such as *Canada's Energy Future 2023* by Canada Energy Regulator and *Shifting Power* published by the David Suzuki Foundation. For example, in *Shifting Power's* Zero Plus Scenario, Alberta's electricity grid quickly becomes dominated by wind and solar, providing large amounts of low-cost clean electricity to both itself as well as British Columbia through expanded interties.[4] Similarly, all scenarios provided in *Canada's Energy Future 2023* predict that wind power will see the most significant growth of any generation technology in Canada — especially in Alberta, Ontario, and Saskatchewan.[5] While these results differ from those presented in the Alberta Electric System Operator (AESO)'s *Net-zero Emissions Pathways* report, our analysis shows that the AESO overestimates capital costs for wind and solar, relies on a very low price forecast for natural gas, and assumes that the status quo (against which the net-zero scenarios are measured) benefits from stagnant carbon pricing policy for decades. For example, *Zeroing In* assumes a $6/GJ natural gas price in 2035 which is $2.3-2.8/GJ more than in AESO's scenarios.

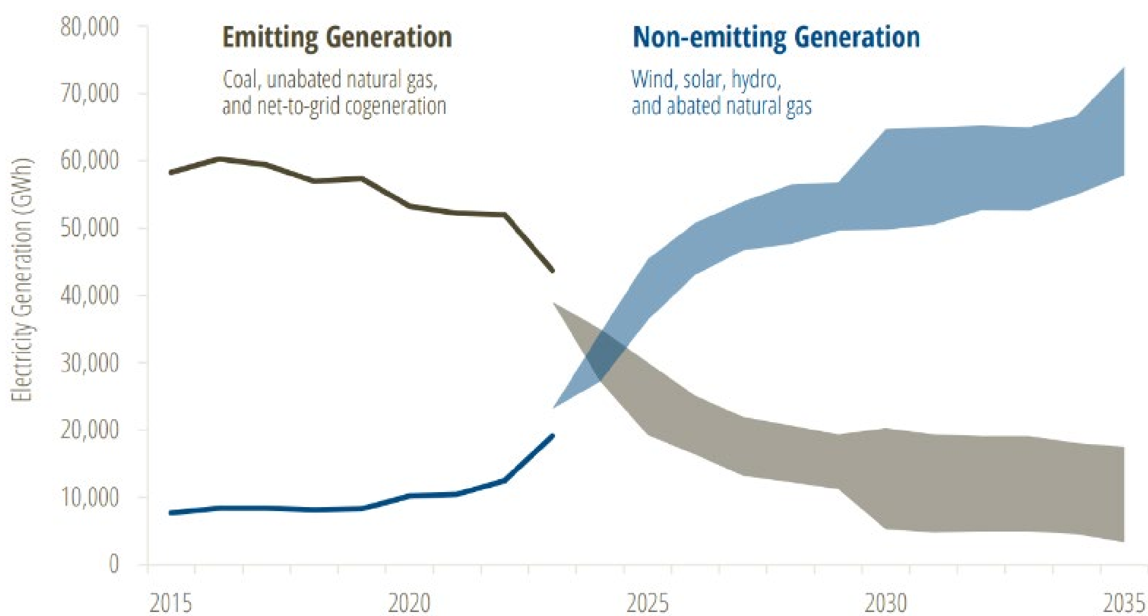

Figure 1. Historical electricity generation (2015-2023) with modelled range to 2035

Source: Pembina Institute[6]

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[4] Stephen Thomas and Tom Green, *Shifting Power: Zero-Emissions Electricity Across Canada by 2035,* (David Suzuki Foundation, 2022), 41-44. https://davidsuzuki.org/science-learning-centre-article/shifting-power-zero-emissions-electricity-across-canada-by-2035/

[5] Canada Energy Regulator, *Canada's Energy Future 2023: Energy supply and demand projections to 2050,* (2023), 69. https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/

[6] Will Noel and Binnu Jeyakumar, *Zeroing In: Pathways to an affordable net-zero grid in Alberta*, (Pembina Institute, 2023), 2. https://www.pembina.org/pub/zeroing-in

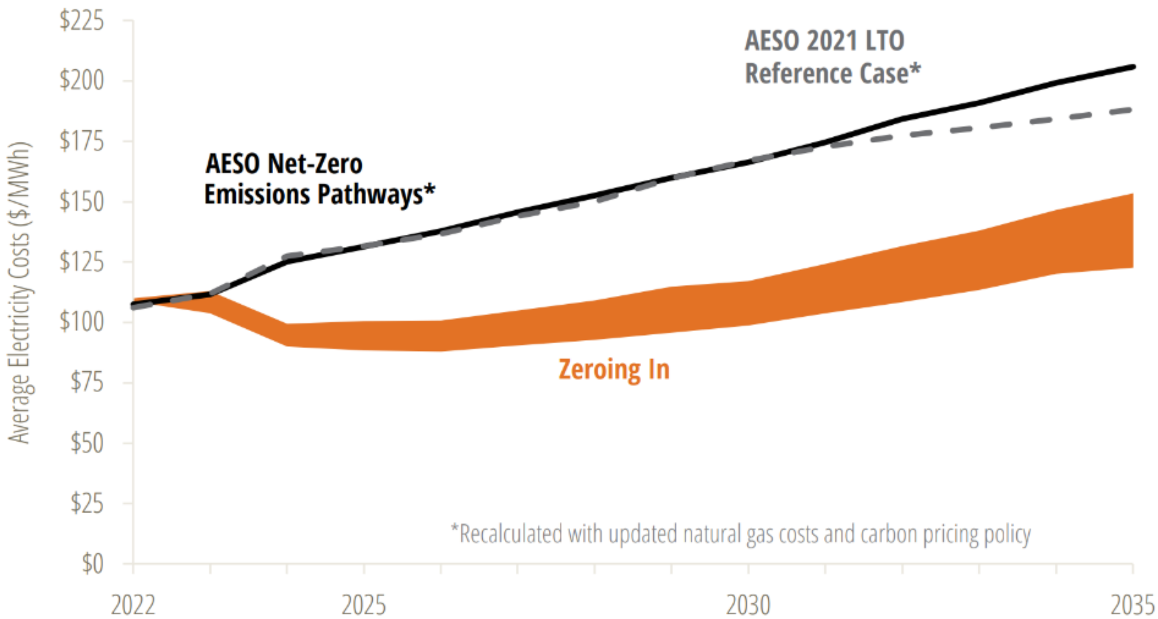

Figure 2. Comparison of *Zeroing In* costs with Alberta Electric System Operators Net-zero Emissions Pathways and Long-term Outlook, 2022-2035

Source: Pembina Institute[7]

Figure 3. Modelled range of net electricity exports in *Zeroing In*, 2023-2035

Source: Pembina Institute[8]

[7] *Zeroing In*, 3.

[8] *Zeroing In*, 44.

While getting to a net-zero grid is not an easy task, in addition to learning from other jurisdictions, we also have some past domestic experience in grid decarbonization, where we can draw best practices and lessons. When the federal *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations* were first introduced in 2012, there were concerns that the accelerated transition off coal would lead to significant increases in transmission costs,[9] thereby shifting the economic burden onto consumers,[10] increasing their power bills by up to three times.[11] In many ways, these concerns are similar to those now being articulated by some stakeholders regarding grid reliability and affordability. These concerns led to the regulations being less stringent, resulting in the last coal plant in Alberta being allowed to operate until 2061. However, Alberta is on track to phase out coal in 2024, nearly four decades before the original timeline. This was achieved through the regulations being updated to a 2030 phase-out target in 2018, and the introduction of an effective carbon pricing scheme for the electricity sector in Alberta and within the federal carbon pricing backstop (Figure 4).

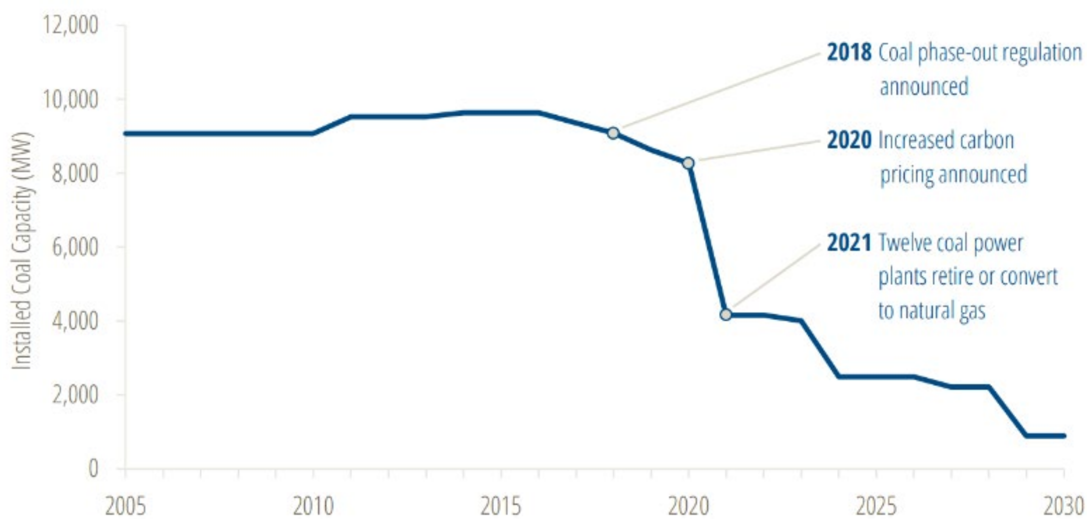

Figure 4. Impact of coal regulations and carbon pricing on accelerating Alberta's coal phase-out

[9] Darcy Henton, "Rising transmission costs pushing Alberta power bills to new heights: report," *Calgary Herald*, March 30, 2016. https://calgaryherald.com/news/politics/rising-transmission-costs-pushing-alberta-power-bills-to-new-heights-report

[10] Calgary Herald Editorial Board, "Editorial: It isn't easy going green (with poll)," *Calgary Herald*, March 19, 2016. https://calgaryherald.com/opinion/editorials/editorial-it-isnt-easy-going-green

[11] Emily Mertz, "Alberta NDP's plan to phase out coal could triple power bills: Coal Association," *Global News*, March 31, 2016. https://globalnews.ca/news/2610760/alberta-ndps-plan-to-phase-out-coal-could-triple-power-bills-coal-association/?sf23462052=1

2.3 Objectives of the CER and complementary regulations

As input is gathered from stakeholders on the draft CER and proposed changes thereto, it is helpful to keep some key outcomes in mind in order to assess the various proposals for changes and the efficacy of the final design.

In its vision for Canada's electricity sector, *Powering Canada Forward: Building a Clean, Affordable, and Reliable Electricity System for Every Region of Canada,* the federal government states that "the proposed Clean Electricity Regulations send a clear regulatory signal that Canada is transitioning toward a net-zero electricity grid by 2035 to help drive investments in the sector... Early, strong, and clear regulatory signals are needed to provide certainty to provinces and territories, investors, and utilities as they plan and operate their electricity systems for a net-zero future."

The Pembina Institute agrees that these are good qualities of a sound regulation to support decarbonization of an energy sector. Given the above, we find the stated objectives of the draft CER in Canada Gazette 1 to be inadequate. The current objectives are to:

- "Help Canada achieve its climate change commitments towards achieving net-zero GHG emissions economy-wide by 2050 by constraining emissions from unabated thermal power generation. This transition will support global efforts to address climate change and help limit associated damage; and
- Reduce GHG (i.e. CO_2) emissions from emitting electricity generation beginning in 2035."

In order to align better with the vision statements and with what is needed to advance towards a net-zero grid by 2035, we suggest updating the objectives to the following:

- "Help Canada achieve its climate change commitments towards achieving net-zero GHG emissions economy-wide by 2050 by constraining emissions from unabated thermal power generation. This transition will support global efforts to address climate change and help limit associated damage; and
- Reduce GHG (i.e. CO_2) emissions from emitting electricity generation *significantly to support progress towards a net-zero emissions grid by 2035*."

We understand that stakeholders have differing views on what is needed to maintain grid reliability in the provinces and how the draft CER design impacts those needs. This has led to different proposals on changes to the CER. In order to evaluate these proposals and the changes being considered for the CER design, we suggest using the following metrics in line with the vision document and the goal of supporting a net-zero grid. We also recommend that the CER be evaluated together with the carbon pricing regulation, as these are the two regulatory tools that will support delivery of a net-zero grid by 2035.

1. **Emissions in the electricity sector in 2035**: In order to achieve a credible net-zero grid — as viewed by our peer countries, international investors, companies seeking clean electricity for their operations, and by civil society — the residual emissions from the electricity sector in 2035 should be as low as possible. The IPCC gives some guidance here by stating that unabated gas generation should not exceed 3% for a net-zero grid.[12]

2. **Incentive for early action in order to reduce emissions and reduce investor risk**: Good policy design should encourage early action in order to reduce cumulative emissions, as climate change is driven by cumulative GHGs in the atmosphere. It should also be noted that Canada has a commitment to achieving a 90% emissions-free grid by 2030. This also prevents a sudden cliff where technologies like carbon capture need to be deployed in a short period of time without a gradual build-out that allows supply chains, skilled labour and other supporting systems to develop and prevents risks for investors.

3. **Netting or negation of the residual emissions on the grid in 2035**: By definition, a 2035 net-zero grid would require that any emissions from the sector be negated, i.e. be offset through carbon removal. Since the CER is no longer intended to deliver a net-zero grid alone, there needs to be parallel mechanisms that ensure continued progress on this metric. The only other regulatory tool that has been referred to in this context amongst stakeholders and in discussions with ECCC is carbon pricing. The current price of carbon and coverage of electricity emissions is clearly inadequate to advance this metric, so changes are needed in the federal Output Based Carbon Pricing System and indications of these changes are needed earlier than the scheduled 2026 review.

The following table summarizes the CER and complementary regulatory elements that can be evaluated by these metrics.

[12] Dave Jones, Matt Ewen and Nicolas Fulghum, "The science is clear, coal needs to go: IPCC scenarios show the urgent need to move from coal power to wind and solar," *Ember*, April 7, 2022. https://ember-climate.org/insights/commentary/the-science-is-clear-coal-needs-to-go/

Table 1. Metrics used to evaluate Clean Electricity Regulations and complementary regulatory elements

Metric	CER policy elements			Complementary regulatory elements	
	End of Prescribed Life	Peaking Provision	Performance Standard	Carbon Pricing*	Offset Mechanisms for net-zero**
Emissions in the electricity sector in 2035	✓	✓	✓	✓	
Incentive for early action in order to reduce emissions and reduce investor risk	✓		✓	✓	
Netting or negation of the residual emissions on the grid in 2035				✓	✓

* Price and coverage of electricity emissions

** Quality of offsets

We assess the elements of the draft CER — as well as proposals for adjustments to the draft CER by other stakeholders — and the need for complementary policy elements with these objectives in mind.

3. CER design elements

This section examines the key design elements of the draft CER. It provides the apparent purpose the element serves, a recommendation for if and how the draft approach should be retained or amended, and analysis supporting our recommendation.

The defining element of the CER is the emissions intensity standard. But there are several very crucial flexibilities and exemptions — in particular the treatment of peaker exemptions, End of Prescribed Life, and cogeneration — that have substantial implications on the residual emissions on the grid and the anticipated generation mix that would meet the electricity demand of the system. This section covers all the above four design features.

We also include recommendations on CER eligibility for remote communities and territorial grids and on the reporting requirements of generating units under the CER, as the data gathered and the transparency of the information will impact the ability to evaluate the efficacy of the CER, to track progress towards a net-zero grid and to hold responsible entities accountable to compliance.

The analysis in this section includes global data as well as data from Alberta, Saskatchewan and Ontario, with a particular focus on grid reliability in Alberta, which has the greatest amount of gas-fired generation.

3.1 Emissions performance standard

Draft CER approach: The CER sets an annual emissions performance standard of 30 t/GWh, and allows units with carbon capture to emit up to 40 t/GWh until the earlier of the first seven years after commissioning or Dec 31, 2039.[13]

3.1.1 Apparent rationale for standard and exemption

The standard is meant to send a clear signal to deter investments in unabated gas-fired generation facilities. While the standard doesn't achieve a 2035 net-zero grid, it is meant to be in support of that goal. A net-zero grid will require residual emissions on the grid to be as low as possible in 2035 and this is the only design element in the CER that aims to support that outcome. The flexibility for carbon capture in its first several

[13] "Clean Electricity Regulations," 2726.

years is meant to allow for operational circumstance that may make it difficult to achieve the standard consistently.

Recommendation: The emissions performance standard should be kept at a level that discourages investments in unabated or incrementally abated gas plants; a weaker standard may be set for before 2035 and ratcheted down in 2035.

3.1.2 Rationale for recommendation

An early standard that ratchets down can incentivize early action, mitigate the risk of regulatory failure, prevent a sudden and lumpy construction surge, and reduce cumulative emissions.

Some concerns have been raised about potential supply chain, labour and other deployment challenges that may arise with the standard coming into effect in 2035. In order to avoid these challenges and to reward early action (which can help to build sector support for sustaining a stable regulation), a less stringent standard could come into effect in 2035 — which would be available to the plant for the rest of its operating life — in advance of the more stringent 2035 standard.

We understand that there is some learning[14] still happening in carbon capture technologies and this mechanism will allow for that without weakening the investment signal for unabated gas.

We suggest then doubling the current flexibility for CCS performance, but only if that lenient standard is applied well before 2035. That is, an 80 t/GWh performance standard can be available for the life of all units that start to operate at that standard by 2030, which is also the year by which Canada has committed to having a 90% emissions-free grid. But after 2030, the standard that needs to be met should be stringent and set at an assumed capture rate of 90-95%.

[14] The two existing, commercial, first- and second-of-their-kind CCS operations on power plants, SaskPower's Boundary Dam and NRG's Petra Nova, were both designed for a 90% capture rate on the emissions they received. After overcoming initial issues they have both demonstrated they can meet or exceed that, and have provided valuable lessons that should be incorporated in future CCS designs to improve their capacity, reliability, and performance. (Reference: International CCS Knowledge Centre, *Canada's Proposed Clean Electricity Regulations – Implications for CCUS*, https://ccsknowledge.com/pub/CCUS%20&%20Clean%20Electricity%20Regulations%20Review.pdf)

3.2 Peaker exemptions

Draft CER approach: The CER allows emitting facilities to "operate at any emissions intensity for a maximum of 450 hours per year, with an [emissions] limit of 150 kt/yr, to provide back-up or peaking capacity."[15]

3.2.1 Apparent rationale for exemption

This provision is intended to target a specific flexibility for the benefit of grid reliability. Peaking power plants (or "peakers") are characterized by their ability to rapidly respond to changes in electricity demand and availability of other generation supply. In electricity grids without sufficient hydroelectric resources or transmission interties — such as Alberta and Saskatchewan — this fast-response balancing role has typically been filled by simple cycle natural gas plants. Gas-fired generation could also be called up to supplement imports and energy storage during more sustained periods of low wind. With these specific grid services in mind, there may be a limited role for small, unabated natural gas power facilities (those unable to meet the physical standard cost-effectively) in a 2035 net-zero grid in some parts of the country, for a very limited set of hours.

> Recommendation: The peaker exemption to the physical standard should not exceed 450 hours of operation.

3.2.2 Rationale for recommendation

The parameters of this exemption should be narrowly outlined to serve this specific objective of enabling peaking services to ensure reliability, and *not* be broadened to achieve other policy objectives that may be advanced by some stakeholders. To be clear, this exemption is *not meant*:

- to avoid or mitigate concerns around stranded capital, which is an issue addressed under the end-of-prescribed-life exemption
- to address grid emergencies, which are addressed under the emergency exemption
- to allow larger facilities where carbon capture investment is feasible to operate unabated

[15] "Clean Electricity Regulations," 2733.

- to allow typically large inflexible facilities (such as industrial cogeneration) to supply the grid without abatement
- to support affordability — because inefficient gas-fired generation, when exposed to a $170/t or higher carbon price, does not provide an affordable outcome for consumers.

The peaker exemption should be limited so as to avoid undermining the regulatory signal for emerging non-emitting options.

Given the global effort to achieve grid decarbonization, including in jurisdictions that presently rely on unabated thermal generation for "peaking," the alternative options available — including rapidly dispatchable non-emitting generation, storage, demand-side management and interconnections — are certain to expand and improve economically. Indeed, as the cost of lithium-ion batteries continues to decline as economies of scale are achieved through widespread adoption, short-duration energy storage is quickly becoming an attractive alternative. The broader the exemption for non-compliant (i.e., unabated, emitting) generation to serve this grid need, the weaker the investment signal for compliant (low- or non-emitting) technology.

Our analysis in Appendix A shows that adding battery capacity to Alberta's simple cycle plants could displace 40 to 80% of the operating hours and generation of these plants. Batteries could be recharged at low cost through wind and solar generation.

The 450-hour limit is more than sufficient to meet electricity demand under the most cost-effective net-zero 2035 scenarios.

It is hard to predict, in advance, the exact functioning of Alberta's electricity sector in 2035. There will be rising electricity demand due to electrification — which, when combined with grid modernization efforts, will offer new opportunities for valuable demand-side management — and greater capacities of wind, solar, and energy storage. Concerns around the 450-hour operating limit steeped in today's thinking might be genuine, but when we look at lowest-cost net-zero 2035 grid scenarios, we see that they overstate the supply adequacy challenges this would create.

Our analysis in Appendix B shows that the combination of storage with a strong complement of wind will support supply adequacy even in the most challenging and lowest-wind hours.

Market redesign conversations that are already underway will allow generators to recover the costs of unabated peaking units within the 450-hour exemption limit

Natural gas peakers will play an important, but limited, role in a net-zero grid. However, as our analysis in Appendix C shows, due to the unfavourable economics of simple cycle natural gas plants in an increasingly decarbonized electricity system, facilities that are still within their amortization period would require additional revenue streams in order to make a return on investment — again, regardless of the CER's unabated peaker exemption limit. In fact, the Alberta Electric System Operator is currently undertaking a Market Pathways Initiative that aims to address potential deficiencies — including the one highlighted above — of the existing market structure in Alberta.[16]

Criticism that the 450-hour unabated peaker exemption limit is insufficient to allow peakers to recover fixed operating costs and remain available is misguided on two accounts:

1) It faults the exemption limit as the cause of the inadequate revenue, even though the changing supply mix will also result in the same effective outcome.
2) It assumes a market design that is in the process of being overhauled specifically to resolve this issue (and, indeed, that government officials have clearly said will be overhauled to ensure revenue adequacy for natural gas).

3.3 End of Prescribed Life

Draft CER approach: **"**Phase in the performance standard on existing units by applying the standard to any given unit 20 years following its commissioning date, known as a unit's End of Prescribed Life."[17]

3.3.1 Apparent rationale for exemption

The purported rationale in the CER for the EoPL exemption is to enable unabated thermal generation to contribute to reliability for a limited time. For some stakeholders, the separate purpose of this provision is to allow operators who have already built unabated gas units some time to recover their investment or enough time to decide if they want to repower as abated gas. Neither rationale justifies an extension of the EoPL.

> Recommendation: The End of Prescribed Life exemption from the emissions performance standard should not exceed 20 years.

[16] Alberta Electric System Operator, "Market Pathways." https://www.aesoengage.aeso.ca/market-pathways

[17] "Clean Electricity Regulations," 2731.

3.3.2 Rationale for recommendation

Given the 450-hour peaker exemption, a 20-year EoPL is sufficient to maintain reliability.

The analysis in Appendix B — demonstrating the sufficiency of the 450-hour peaker exemption to retain supply adequacy for most fleet scenarios — assumed a 20-year EoPL for unabated firm non-peaking generation. Therefore, our analysis indicates that a 20-year EoPL, combined with a 450-hr unabated peaker exemption, is adequate to support reliability.

The 20-year EoPL already enables the orderly transition away from unabated thermal generation. Year by year, as plants hit the 20-year EoPL, operators can decide whether to abate, work within the peaker exemption, or retire the facility. This means that units will be retired gradually rather than all together when the regulations come into effect. With a 20-year EoPL, there will still be a large amount of unabated gas capacity on the grid in 2035 — 5,828 MW in Alberta, 934 MW in Saskatchewan, and 1,683 MW in Ontario — that is not covered by the CER. This includes both existing capacity and facilities that are currently under construction with commissioning dates prior to January 1, 2025.

There is no compelling investment expectation justifying an extension of the EoPL beyond 20 years.

Neither the CER nor the federal government need to bear the burden of investment decisions that were made — particularly those in the last three to five years and in the next few years until January 2025 — without due consideration for the global outlook on decarbonization. The IEA has been calling for a net-zero grid by 2035 in OECD countries since 2021.[18] Moreover, there is evidence that natural gas power investments can be recovered well within the EoPL currently defined as 20 years.[19]

The 20-year EoPL leaves substantial emissions on the grid, challenging the achievement of a net-zero grid. A further extension beyond 20 years would aggravate this situation.

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[18] IEA, *Net zero by 2050: A roadmap for the global energy sector* (2021), 20. https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf

[19] Rexon Carvalho, Eric Hittinger, and Eric Williams, "Payback of natural gas turbines: A retrospective analysis with implications for decarbonizing grids," *Utilities Policy* 73 (2021). https://www.sciencedirect.com/science/article/abs/pii/S0957178721001417

Under the current design of the CER, we estimate that there will be 7 $MtCO_2e$ of electricity emissions in Alberta in 2035. As noted above, nearly 6,000 MW (almost half of Alberta's current peak load and over one-third of Alberta's current total installed capacity of all generation) of natural gas power will be allowed to operate at any level to generate unabated, emissions-intensive electricity, in 2035. This poses a considerable threat to the achievement of the government's commitment to a net-zero grid in 2035. The volume of remaining emissions from such a large fleet of unabated fossil-fuel-fired generation is beyond what can credibly be termed "residual," a term that suggests a *de minimis* volume left after pursuing abatement and alternatives.

The challenge continues beyond 2035, even as a clean electricity sector is needed to support broader decarbonization en route to our international commitment to a 2050 net-zero economy. There are 3,205 MW of new or repowered gas-fired generation targeting operations by December 2024 in Alberta which, when operational, could singlehandedly meet 37% of the province's 2022 peak grid demand and 32% of its annual electricity consumption.[20] The 20-year EoPL would allow this new capacity — which began capital investment well after the federal government's 2035 net-zero grid commitment dating back to 2021 — to emit unabated at any level of operation until the end of 2044.

By increasing the EoPL above 20 years, the amount of unabated capacity that can operate above the performance standard would increase, leading to even more remaining grid emissions. A five-year extension would increase 2035 grid emissions in Alberta by up to one-third from the current CER design.[21] It would risk 3,205 MW of unabated, unconstrained fossil-fuel generation right up to the end of 2049, the very last moment before Canada is committed to realizing a net-zero economy, which the net-zero grid is crucial to enabling. This is far too much regulatory, economic and negative-emissions supply risk.

3.4 Cogeneration and behind-the-fence generation

Draft CER approach: **"**In any given compliance year, industrial units that have net exports to a NERC-regulated electricity system (i.e. they sell more electricity than they

[20] Assuming peak grid demand is 71% of peak system demand — which includes behind-the-fence activities at industrial facilities —and a capacity factor of 70%. *AESO 2022 Market Statistics*, 8

[21] This analysis assumes that natural gas plants that are not constrained by the CER will operate at the same capacity factor as they did in *Zeroing In*, i.e. simple cycle: 36%, combined cycle: 40-50%, gas-fired steam: 20%, and cogeneration exports to grid: 14%.

buy) would have to meet the proposed Regulations' performance standard in that year."[22]

3.4.1 Apparent rationale for criteria

The inclusion of the net export criteria will "distinguish between those facilities that are connected to an electricity system… as a consumer versus those that are connected… as a generator." [24] This inclusion of facilities with net-exports will ensure fair treatment of these facilities compared to generators that sell all their production on to the grid.

> Recommendation: Cogeneration units that have net exports to the grid should be subject to the CER standard.

3.4.2 Rationale for recommendation

Exempting industrial cogeneration in Alberta would undermine fair competition by advantaging a very large market participant over other generators.

In Alberta, industrial cogeneration forms a large proportion of Alberta's electricity system. Typically, these facilities are oversized relative to their behind-the-fence electricity demand. Indeed, around 40-43% of total cogeneration output is exported to the grid (Figure 5). Their power makes up approximately 22% of Alberta's electricity market. They benefit from large grid investments made a decade ago to transmit their electricity to the lucrative Alberta market. While their operations may be conjoined with other industrial production, they are truly electricity generators and electricity market participants by any definition.

[22] "Clean Electricity Regulations," 2734.

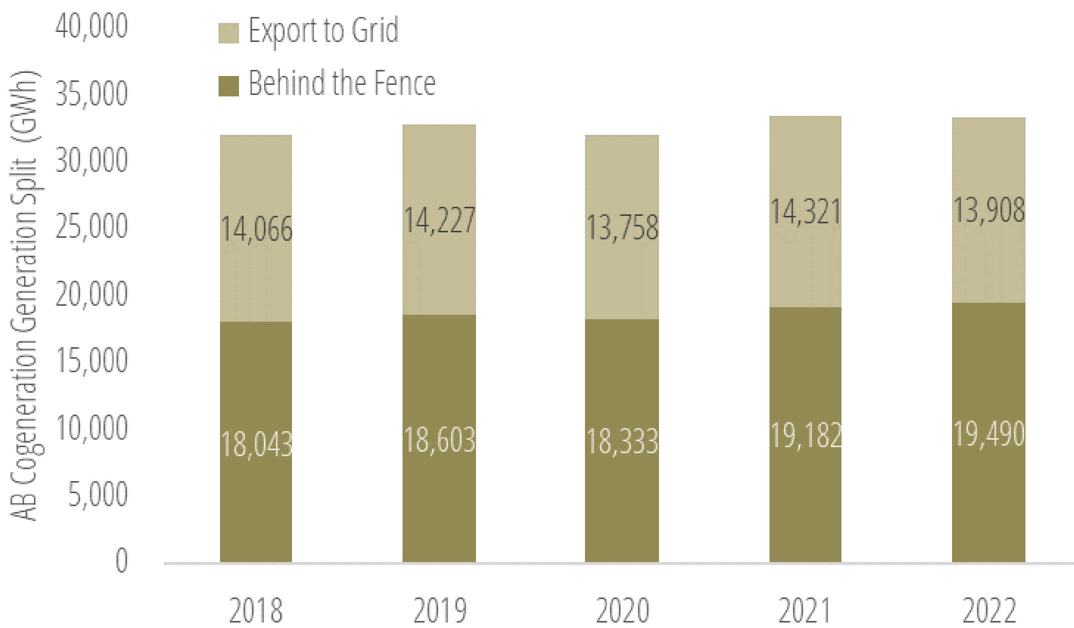

Figure 5. Cogeneration operations in Alberta, 2018-2022

These power plants compete with other generation on the grid. Given the additional investment required and/or operational restrictions imposed on those facilities by the CER, it would be an unfair economic advantage for cogeneration to be exempt. Indeed, this signal would undermine emissions abatement and non-emitting generation investments by other market participants by pitting them in unfair competition against a large pool of exempt cogeneration players. This would clearly undermine the fair, efficient and open competition operation of Alberta's electricity market, destroying investor confidence in the market price signal.

Meanwhile, many cogeneration facilities would enjoy similar opportunities for abatement through carbon capture as large combined-cycle gas power plants. Indeed, cogeneration operators have long touted the feasibility and effectiveness of carbon capture for their operations.[23]

Net-to-grid cogeneration is not critical for reliability of Alberta's grid.

Cogeneration does not provide as much value for grid reliability or balancing as some competitors. Given that the electricity generation is secondary to the primary industrial operations' requirement for steam or heat, its generation is much less flexible or

[23] See, e.g., Pathways Alliance, "Carbon capture and storage (CCS)." https://pathwaysalliance.ca/foundational-project/carbon-capture-and-storage-ccs/

responsive to grid needs. As such, cogeneration does not warrant any special treatment for realizing reliability outcomes.

Indeed, the possibility that cogeneration could cease to net-export to the grid in response to the CER is not detrimental to our system. As the analysis in Appendix B (which assumed that cogeneration that hits EoPL will cease to export to the grid) shows, grid reliability can be sustained under a 20-year EoPL and with a 450-hour limit to the peaker exemption, even without cogeneration export.

If the revenue from the grid is not sufficient for cogeneration operators to justify deploying abatement (despite their many assertions around the opportunities of CCS for their operations, when seeking public funding), then — given that the energy market prices electric energy through real-time supply and demand dynamics — this reveals that the cogeneration is providing valuable reliability and low-cost energy only for the behind-the-fence oilsands operation itself, but not for the grid.

Exempting the behind-the-fence portion of cogeneration in Alberta would create a very large loophole allowing considerable unabated emissions.

In 2022, Alberta had 5,880 MW of cogeneration capacity, making up 32% of Alberta's total installed capacity (18,463 MW).[24] With over half of the energy being used behind the fence (Figure 5), a significant portion of Alberta's electricity emissions are a result of self-served generation at these industrial facilities. We estimate that this behind-the-fence electricity generation is responsible for 5-6 $MtCO_2e$ (15-17%) of Alberta's current annual electricity emissions. If carved out of the CER's regulatory impact, this would make up increasing proportions of annual grid emissions as the rest of the grid decarbonizes.[25]

Other industrial sectors besides electricity are under increasing regulatory and competitiveness pressure to decarbonize, which means many cogeneration operators will have incentives and requirements to abate coming from multiple directions, not just the CER. This means the business case for carbon capture on cogeneration will often have more going for it than many other types of gas-fired generation. This competitive advantage means it is unlikely they will curtail exports under the CER.

In sum, industrial cogeneration benefits considerably from its connection to and revenue generation from the grid, while its emissions — both with respect to behind-

[24] Alberta Utilities Commission, "Alberta Electric Energy Net Installed Capacity (MCR MW) by Resource," (2022). https://www.auc.ab.ca/annual-electricity-data/

[25] Assumes an emissions intensity of 0.299 t/MWh. *Zeroing In*, 61.

the-fence and net-to-grid generation — are a considerable proportion of Alberta's grid emissions. Any exemptions for this electricity would undermine the claim to a truly net-zero grid while harming Alberta's market competition and investor confidence.

3.5 CER eligibility for remote communities and territorial grids

Draft CER approach: The CER will apply to units that are connected to an electricity system that is subject to NERC standards. The "compliance flexibilities have been designed to effectively exempt most Indigenous communities and northern, rural and remote communities not connected to a NERC-regulated electricity system."[26]

3.5.1 Apparent rationale for criteria

The draft CER states that rural and remote communities "often lack affordable options to use non-emitting electricity generation."[27] However it also notes that the federal government will continue consulting with Indigenous communities on the design of the regulation, as several communities are also interested in participating in the clean energy transition.

> Recommendation: Remote communities and territorial grids must be included in the CER or given the option to opt into the CER to ensure they are included in efforts to decarbonize Canada's electricity generation.

3.5.2 Rationale for recommendation

A full 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.

Further engagement with Indigenous communities, organizations, and rightsholders is necessary to support the appropriate adoption of this regulation.

[26] "Clean Electricity Regulations," 2810.

[27] "Clean Electricity Regulations," 2811.

3.6 Reporting

Draft CER approach: The CER will require units to report on an annual basis "information such as the unit's annual average emission intensity ... gross generation; emissions and hours of operation."[28]

Recommendation: The CER should require reporting of the emissions, emissions intensity, hours and net-to-grid export of each unit on an annual basis, and this data should be publicly available.

3.6.1 Rationale for recommendation

Better transparency in Canada's electricity generation emissions performance is a key — and overdue — condition precedent to successfully achieving a net-zero grid.

In order to monitor and enforce the regulations effectively, generators must report the absolute emissions, emissions intensity, hours of operation and net-to-grid export of each unit on an annual basis. To foster public, consumer, and investor confidence in the net-zero outcome, this information must be made public to enable scrutiny and accountability.

Moreover, public transparency, including before 2035, is essential to inform public discourse, enable valuable research to promote continuous improvement of grid emissions performance toward net-zero, and allow for course correction policies if the trajectory to net-zero is threatened. The data gathered and the transparency of the information will impact the ability to evaluate the efficacy of the CER, to track progress towards a net-zero grid and to hold responsible entities accountable to compliance.

Despite concerns about the commercial nature of this information, this type of data disclosure is not uncommon for environmental regulations; it has been common practice in U.S. states for many years. It is also seen in Alberta's power sector regulations around nitrous oxides and sulphur dioxide, with annual emissions and generation posted publicly.

[28] "Clean Electricity Regulations," 2728.

4. Carbon pricing clarity for a credible path to a net-zero grid

The draft CER openly acknowledges that the regulations alone do not achieve a net-zero grid — particularly because there is no financial compliance mechanism within the CER to require offsetting or "negating" of remaining emissions in 2035 — and thus complementary measures will be required.[29] ECCC presentations have mentioned that this mechanism may be through carbon pricing. However, the federal Output Based Pricing System currently has no indication of what industrial carbon pricing for electricity will be after 2030.

Recommendation: At the time of publication of the final CER, the federal government must announce its intention to revise the OBPS to require full pricing of all electricity sector emissions in all provinces, which revenues should be used to procure tonne-for-tonne negative emissions.

4.1.1 Rationale for recommendation

Full carbon pricing of electricity emissions, in the context of the CER and the broader net-zero grid goal, is essential for two key reasons:

1. To ensure that the CER's flexibilities have minimal impacts in terms of remaining emissions by creating clear incentives for those operating under the flexibilities to reduce emissions and providing sufficient signals to low- or non-emitting alternatives.
2. To meet the government's net-zero grid 2035 commitment by "netting" the residual emissions through tonne-for-tonne procurement of negative emissions.

As such, in order to evaluate the sufficiency of the CER against the key metric of attaining the federal government's commitment to a net-zero grid in 2035, the Pembina Institute and other stakeholders need to see certainty around the robustness of electricity sector emissions pricing across Canada.

[29] "Clean Electricity Regulations," 2743.

Full pricing of electricity emissions is essential to plugging the CER's exemption gaps and to setting a physical emissions path in line with a net-zero grid.

First, the exemptions available under the draft CER — including particularly the peaking exemption and the EoPL — are palatable only if a strong emissions pricing signal incentivizes the narrowest possible use of these exemptions. As noted in prior sections, these exemptions allow for potentially very large emissions in 2035 and beyond. For example, the nearly 6,000 MW still protected by a 20-year EoPL in 2035 could, if operating at high capacity factors seen with some plants in recent years, emit up to or even above 20 $MtCO_2e$. The over 3,000 MW new builds still under EoPL in 2044 could emit up to 7 or 8 Mt.

A clear policy commitment, at the time of publishing the final CER, to fully price all electricity emissions by 2035 on a schedule rising above $170/t will give confidence that these exemptions will not be abused beyond their intended objective (principally, to maintain reliability). This is a change from the current schedule for free allocations under the OBPS out to 2030 for, for example, existing (beginning operations before 2021) facilities. This change would fix an issue that undermines the price signal particularly because these production subsidies (free allocations) are not provided to non-emitting generation.

This is also a change from the current ECCC plans to review the benchmarks in 2026 for the 2027-2030 period and beyond. Immediate clarity around the elimination of free allocations for all facilities by 2035, on a declining schedule beginning in 2031, is essential. To be clear, for this to be effective, this must apply to all electricity emissions, regardless of their exemption status under CER applicability (such as the 25 MW threshold, EoPL or peaking).

Full pricing of emissions at a price sufficient to procure tonne-for-tonne negative emissions is necessary to credibly substantiate a net-zero grid claim.

Prior frameworks for the CER indicated an intention to achieve net-zero through "netting" of emissions via a financial compliance mechanism. The financial compliance option (i.e., including payment for emissions) was already watered down relative to a requirement that emitters negate their emissions. However, the CER ultimately excluded even the financial compliance mechanism, leaving the "netting" of remaining emissions to other policy, particularly emissions pricing under the OBPS regime.

This approach can be credible, so long as:

- All electricity emissions are priced with no free allocations.

- The price is high enough to enable procurement of negative emissions and the government uses revenues for that purpose on a tonne-for-tonne basis.
- Provincial industrial carbon pricing schemes are evaluated much more stringently for equivalency against the OBPS benchmark than they currently are, and with a sector-specific lens. The electricity sector emissions pricing cannot be weakened relative to the OBPS due to a “whole-of-package" approach across the industrial sectors during the federal benchmarking review.

Alternatively, if the generator can find cheaper negative emissions that meet stringent standards around credibility — i.e. with offsets that comply with stringent protocols — they should be permitted to negate their own emissions, rather than pay the financial compliance option under the OBPS. Regardless, these requirements will provide crucial investor certainty and instigate an early sector growth trajectory for negative emissions/ carbon removal technologies like direct air capture, which needs to ramp up en route to 2050.

While we have shown that significant decarbonization will not increase electricity costs, as a proactive measure, the federal government and provinces should commit to ongoing joint work to monitor and ensure electricity affordability is maintained, especially for the most vulnerable consumers.

Appendix A. Peaking capacity through storage

Storage technology that already exists today could supplant the majority of the role of simple cycle natural gas plants in providing peaking capacity.

Alberta currently has 25 simple cycle natural gas plants with a total fleet capacity of approximately 1 GW. Some of these assets are not run as peaking facilities as their operation is dependant on factors outside the bulk electricity system.[30] Figure 6 shows the range of dispatch hours for each individual simple cycle plant that operates as a peaker, where each dispatch is classified by the amount of time the plant is operating continuously until it is sent the signal to shut off. Figure 7 shows the amount of electricity generated during each of those dispatches. Together, these figures show that the majority of Alberta's peaking fleet is dispatched for five to 15 hours each time it is called upon and that the electricity generated during those hours ranges, on average, from under 1 MWh to 1,500 MWh, owing largely to differences in capacity. Due to the infrequency of operation and the limited total operating hours of these assets, short-duration energy storage options already available today could serve much, if not all, of their function, recharging between dispatches. This non-emitting option will only become more feasible as storage technology proliferates and improves (in capital cost and efficiency).

[30] For example, the primary function of the Rainbow #5 simple cycle plant is to provide electricity to the Rainbow Lake natural gas processing plant with which it is co-located. Similarly, the West Cadotte simple cycle plant uses diverted flare gas from the adjacent facility.

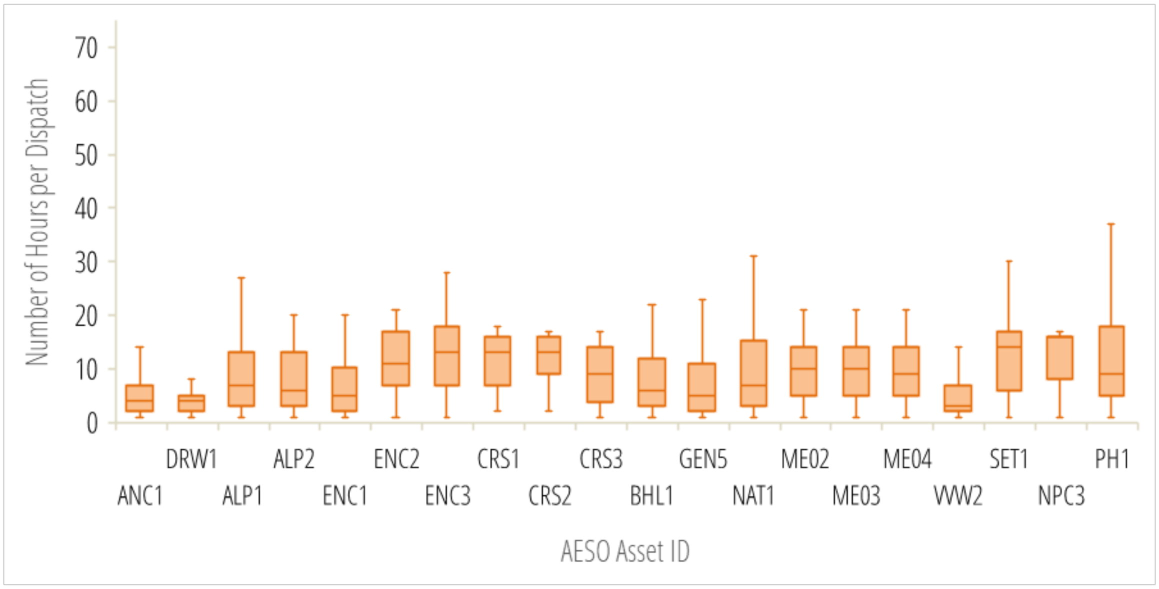

Figure 6. Dispatch hours for Alberta simple cycle assets, 2022

Data source: Alberta Electric System Operator[31]

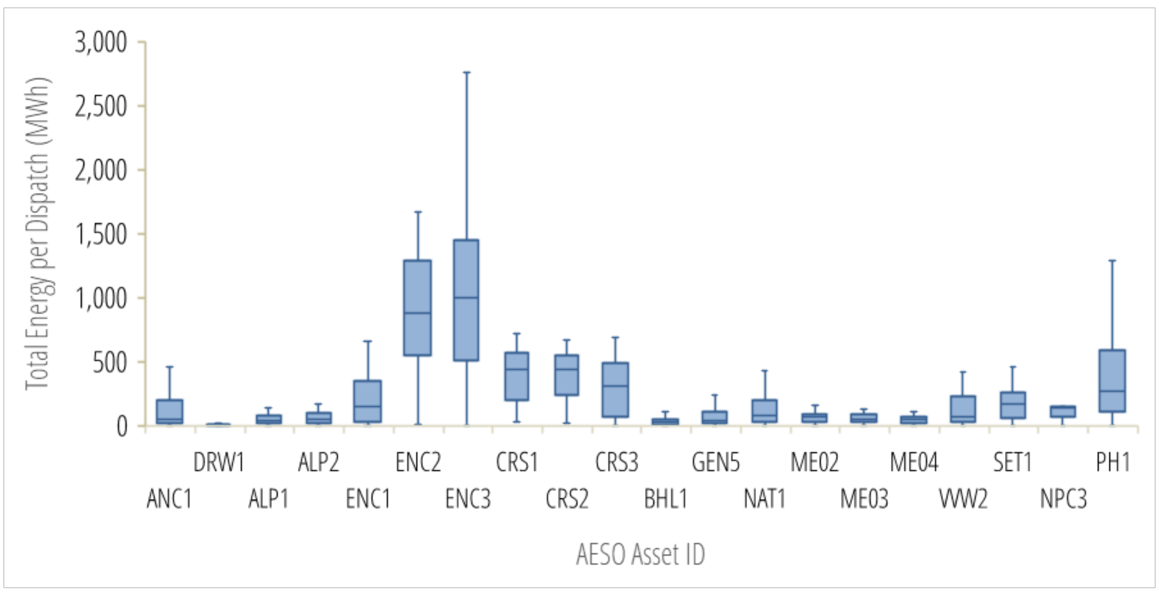

Figure 7. Electricity generation per dispatch of Alberta simple cycle assets, 2022

Data source: Alberta Electric System Operator[32]

Figure 8 shows the significant decrease in 2022 peaking unit operating hours that could have been achieved through the addition of a battery. For example, augmenting each simple cycle plant with a 4-hour battery of the same installed capacity — 803 MW in

[31] *AESO, Metered Volumes*

[32] *AESO, Metered Volumes*

total — could displace nearly half of the generation and operating hours of the original fleet. Similarly, co-locating each simple cycle plant with 100 MW of 4-hour storage could cover more than two-thirds of the generation and 80% of the operating hours. While this simple analysis assumes that the energy storage assets would be fully charged prior to being dispatched, the continued expansion of Alberta's wind and solar fleets will provide ample opportunity for low-cost charging. As such, the need for unabated gas for peaking requirements is already a matter of debate, not a settled assumption, never mind with the advancements in non- or low-emitting technology 12 years out.

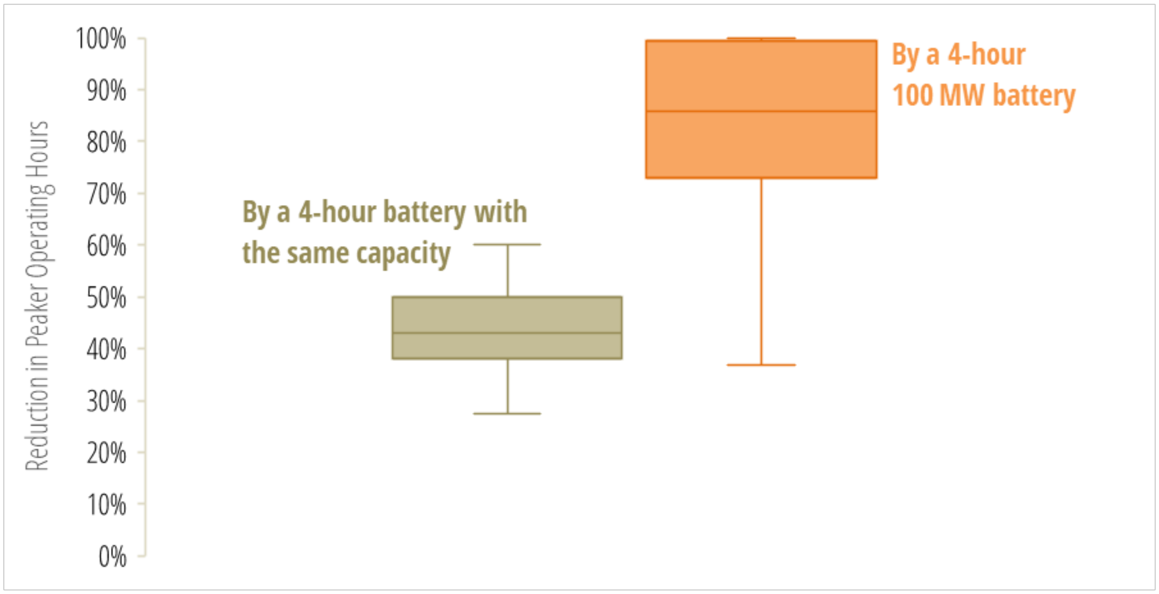

Figure 8. Decrease in simple cycle operating hours through the addition of different sizes of battery, 2022

Appendix B. Modelling supply adequacy

To quantify the potential risk of unserved energy in 2035, we looked at a worst-case scenario analysis of Alberta's electricity grid, considering a range of fleet mixes including firm generation, renewables, intertie availability, and energy storage.

B.1 Modelling assumptions

Our very conservative assumptions for this supply adequacy analysis are as follows:

- Wind assets will follow the same generation pattern as in 2010[33] — a particularly low-wind year in Alberta — scaled up to 2035 installed capacities which conservatively range across the scenarios from 5,000 MW to 10,000 MW.[34]
- Hydro assets are derated by 50%.
- Natural gas plants are derated by 13%, based on 2022 outage data,[35] with total installed capacity based on the 20-year End of Prescribed Life (EoPL) set in the draft CER. Only existing assets plus a select few projects under construction with a 2024 commissioning date (Cascade, Base Plant, and Genesee 1 and 2) are included.[36]

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[33] Alberta Electric System Operator, "Data Requests: Hourly Metered Volume and Pool Price and AIL Data 2010 to 2022," (accessed July 7, 2023). https://www.aeso.ca/market/market-and-system-reporting/data-requests/

[34] The 5,000 MW low end of the scenario range includes existing capacity (3,853 MW) plus approximately 25% of projects in AESO's queue that have met their inclusion criteria as of October 2023. The high end of 10,000 MW includes existing capacity plus all projects that have met inclusion criteria plus 33% of projects that are in the queue but have not met the inclusion criteria. (Alberta Electric System Operator, "October 2023 Connection Project List." https://www.aeso.ca/grid/transmission-projects/connection-project-reporting/) The upper limit considered in this analysis is less than the wind fleets in all six scenarios of *Zeroing In*, which ranged from 10,800 MW to 19,300 MW. (*Zeroing In,* 46.)

[35] Alberta Electric System Operator, "Annual market statistics data file," (2023). https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/

[36] This does not include the 567 MW of natural gas projects that (as of October 2023) have received regulatory approval, with an expected start date before January 2025, but which are not yet under construction. ("October 2023 Connection Project List.")

- Cogeneration assets that do not fall within the 20-year EoPL are assumed to stop exporting electricity and are removed from the study. In other words, as a worst-case scenario from a generator availability point of view, we assume they will opt to move their operations completely behind the fence rather than abate, a conservative assumption given industry plans for abatement.
- Transmission interties are derated by 20-35%.
- System demand is taken from the Alberta Electric System Operator's Net-Zero Emissions Pathways Report.[37]

Given the assumptions outlined above, we ran an analysis on 12 potential generation fleets with varying levels of installed wind capacity, energy storage capacity, and firm generation availability, including natural gas generators exempt from the CER under the 20-year EoPL provision, interties, hydro, and biomass. Each analysis also includes a fleet of flexible natural gas generators — not including cogeneration or coal-to-gas boilers — that are limited to 450 operating hours per unit.

B.2 Results

Figure 9 shows the range of unserved energy resulting from the 450-hour limit placed on gas-fired generation units as well as the number of gas generation hours required to alleviate the unserved energy. Unsurprisingly, the fleets with the lowest available generation capacity (1-3) — resulting from a combination of the lower bookend scenarios for wind (5,000 MW), energy storage (500 MW/2,000 MWh), and intertie utilization (35% derate) — are found to perform the worst of all our analyses, requiring an additional 200-325 hours of peaker operations on top of the 450-hour provision. However, under fleet scenarios with higher wind and storage deployment — a more accurate representation of a decarbonized grid and better aligned with recent forecasts including *Zeroing In*, *Canada's Energy Future 2023*, *Shifting Power*, and the IEA's 2023 World Energy Outlook — we find that energy demand is met more consistently and eventually without requiring the full 450 hours peaking provision, meaning a tighter exemption can still enable reliability.[38] This result underscores the importance of a diversity of technologies in ensuring the robust operation of a decarbonized electricity grid.

[37] Alberta Electric System Operator, "Excel | AESO Net-Zero Emissions Pathways Data File," (2022). https://www.aeso.ca/future-of-electricity/net-zero-emissions-pathways/

[38] Notably, the model employed storage operation sequentially across all hours, charging and discharging the storage assets in an attempt to avoid unserved energy. The charge/discharge cycles are constrained by: wind/solar availability, battery charge capacity (MW), discharge capacity (MW), and energy capacity (MWh).

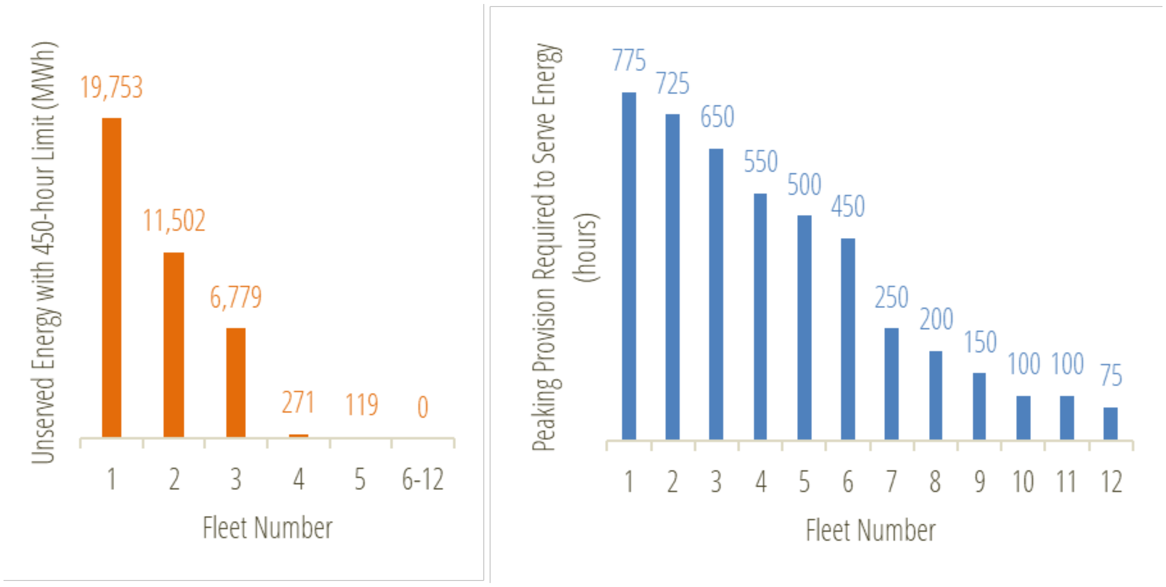

Figure 9. Results of peaking provision analysis in the worst-case scenario, annual totals for 2035

It is noteworthy that this result is partly accomplished by what is sometimes called an "overbuild" of zero-marginal-cost generation, particularly wind, so-called because the amount of $0/MWh-bid generation on the system is greater than system load in some hours. Some analysts and commentators see this as a negative and even hardwire their analysis against it, but because wind energy is so inexpensive, it can provide lowest-cost outcomes even with some curtailment. And, in a system with increasing levels of installed wind capacity, excess kinetic energy from the newer wind turbines could be used to provide synthetic inertia to mitigate frequency disturbance events.[39] At the same time, interties and more storage can help to create economic value from the excess energy. The key point is that the combination of storage with a strong compliment of wind will support supply adequacy even in the most challenging and lowest-wind hours.

[39] In an electricity grid, the inertia of large rotating generators in conventional power plants can be used to smooth perturbations in grid voltage and frequency. Wind-driven synthetic inertia is not a new concept. In 2005, Hydro Quebec introduced a new mandate requiring all new wind turbines to be capable of providing this service, with the first being installed in 2011. By 2016, two-thirds of Quebec's wind capacity was made up of inertia-compliant turbines. (Peter Fairly, "Can Synthetic Inertia from Wind Power Stabilize Grids?" *IEEE Spectrum*, November 7, 2016. https://spectrum.ieee.org/can-synthetic-inertia-stabilize-power-grids)

Appendix C. Modelling gas plant operations

Using hourly pool prices from the Pembina Institute and University of Alberta's research in *Zeroing In*, we can find the number of hours that a simple cycle natural gas plant would need to be dispatched to recover its costs.

C.1 Modelling assumptions

Table 2 outlines the parameters used to calculate the cost of operating a simple cycle natural gas plant in 2035 in this analysis.

Table 2. Summary of assumed simple cycle costs

Parameter	Value
Inputs	
Capital Cost ($/kW)	1,125
Weighted Average Cost of Capital (%)	10%
Operating Life (years)	20
Financing Cost ($/kW-year)	132
Variable Operating Cost ($/kWh)	6
Fixed Operating Cost ($/kW-year)	20
Heat Rate (GJ/MWh)	10.3
Emissions Intensity (tCO_2e/MWh)	0.62
Natural Gas Price ($/GJ)	5.82
Carbon Price ($/$tCO_2e$)	170
TIER Benchmark for Electricity (tCO_2e/MWh)	0
Results	

Fixed Costs* ($/kW-year)	152
Variable Costs** ($/MWh)	171

* Fixed Costs include amortized capital costs and fixed operating costs
** Variable Costs include variable operating costs, fuel costs, and emission costs

C.2 Results

Table 3 outlines the number of hours that it would be economic for a newer simple cycle natural gas plant (one which is still making amortization payments) to operate under each scenario from *Zeroing In*, as well as the economic performance of that plant if it was dispatched during those hours.

Table 3. Economic performance of a simple cycle natural gas plant that is making amortization payments in a decarbonized electricity grid, 2035

Scenario	Number of economic operating hours*	Deficit if operated in those hours**	
		Energy ($/MWh)	Capacity ($/kW)
High Credit	826	210	95
Baseline	526	187	84
Increased Trade	365	207	93
High Storage	617	191	86
Near-Zero	469	244	110
Near-Zero+	695	208	93

* The number of hours that the electricity pool price is greater than the marginal operating cost of a simple cycle natural gas plant. Or, in other words, the number of hours that a simple cycle asset can earn more than it costs to operate.
** The difference between annual costs and revenues divided by total generation (left) or installed capacity (right)

Results of this analysis show that, under the current market design in Alberta, it may no longer be economic to operate a newer natural gas peaking plant in 2035, regardless of the regulated peaking exemption limit. Across all six scenarios, assuming a peaking plant is dispatched only during the hours that the pool price is higher than its operating costs, it would need an additional $187-244/MWh of energy revenue or $84-110/kW of capacity or reliability payments in order to cover its costs. Because the deployment of high levels of wind and storage with much lower marginal operating costs will limit the use of expensive gas peakers as a function of the market, this inadequate revenue would arise under the current market design *regardless of the CER's unabated peaker exemption limit.*

It is worth noting that this analysis assumes the peaker is still paying amortized capital costs, making it presumably less than 20 years old. In other words, the results presented in Table 3 are for a simple cycle natural gas plant that is not yet covered by the CER due to the EoPL provision. Even with the EoPL exemption, the plant is not economic — not because of the limited hours under the exemption, but because these scenarios have high levels of lower marginal operating cost generation. A weaker peaker exemption (higher number of hours) will not solve this.

We can perform the same analysis as above for a peaking plant that has accomplished its amortization by removing the $132/kW-year capital financing cost in the initial assumptions (Table 2). In this case, the plant would be limited to a maximum of 450 operating hours, as we assume that it is now outside the 20-year EoPL window. Table 4 outlines the economic performance of a time-constrained peaking plant in 2035, assuming it is no longer making amortization payments. Results of this analysis show that 450 hours of peaking operation is more than enough time for this type of plant to make an economic return in a 2035 Alberta electricity grid. In other words, despite their high marginal operating costs, there is sufficient revenue opportunity for existing natural gas peakers to operate under the current CER peaking provisions, even with Alberta's existing market design.

Table 4. Economic performance of a time-constrained simple cycle natural gas plant that is no longer making amortization payments in a decarbonized electricity grid, 2035

Scenario	Economics if operated for up to 450 hours		
	Costs ($/MWh)	Revenue ($/MWh)	Profit ($/MWh)
High Credit	216	418	202
Baseline	216	336	120
Increased Trade	216	287	71
High Storage	216	354	138
Near-Zero	216	270	54
Near-Zero+	216	367	151

Natural gas peakers will play an important, but limited, role in a net-zero grid. However, due to the unfavourable economics of simple cycle natural gas plants in an increasingly decarbonized electricity system, facilities that are still within their amortization period would require additional revenue streams in order to make a return on investment — again, regardless of the CER's unabated peaker exemption limit. In fact, the Alberta Electric System Operator is currently undertaking a Market Pathways Initiative that aims to address potential deficiencies — including the one highlighted above — of the existing market structure in Alberta.[40] On the other hand, existing peakers that are outside their amortization window — here, assumed as 20 years and thus ineligible for exemption under the EoPL provisions — would be able to make an economic return under a 450 hour operating limit. As such, this analysis indicates that any criticism that the 450-hour unabated peaker exemption limit is insufficient to allow peakers to recover fixed operating costs and remain available is misguided on two accounts:

1) It faults the exemption limit as the cause of the inadequate revenue, even though the changing supply mix will also result in the same effective outcome.

2) It assumes a market design that is in the process of being overhauled specifically to resolve this issue (and, indeed, that government officials have clearly said will be overhauled to ensure revenue adequacy for natural gas).

[40] Alberta Electric System Operator, "Market Pathways." https://www.aesoengage.aeso.ca/market-pathways