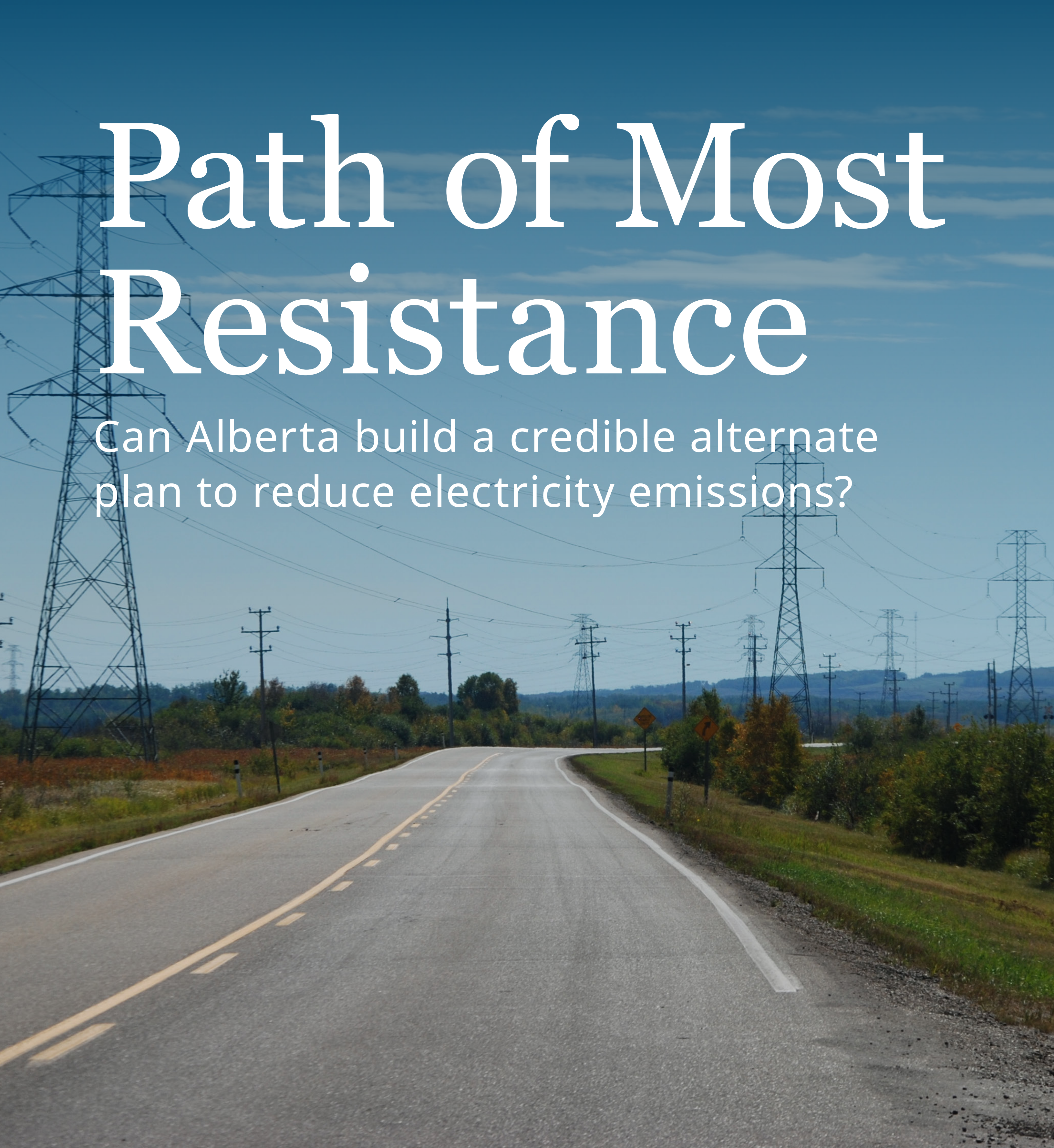

Path of Most Resistance

Can Alberta build a credible alternate plan to reduce electricity emissions?

March 2026

Will Noel

PEMBINA Institute

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Acknowledgements

The Pembina Institute recognizes that the work we steward and those we serve span the lands of many Indigenous Peoples. We respectfully acknowledge that our organization is headquartered in the traditional territories of Treaty 7, comprising the Blackfoot Confederacy (Siksika, Piikani and Kainai Nations); the Stoney Nakoda Nations (Goodstoney, Chiniki and Bearspaw First Nations); and the Tsuut'ina Nation. These lands are also home to the Otipemisiwak Métis Government (Districts 5 and 6).

These acknowledgements are part of the start of a journey of several generations. We share them in the spirit of truth, justice and reconciliation, and to contribute to a more equitable and inclusive future for all.

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Executive summary

Following the November 2025 memorandum of understanding (MOU) on climate and energy signed by the Government of Alberta and the Government of Canada, the two are in active negotiations with regards to Alberta's electricity sector emissions. It appears Alberta wishes to forge its own regulatory path to achieve its commitment of a net-zero grid by 2050. To do so, it must demonstrate during the MOU talks that it has a credible alternate plan to achieve the same emissions outcomes of the Clean Electricity Regulations — including detailed measures and timelines with a realistic chance of success.

It is not sufficient to rely almost solely on expensive and unproven technologies — carbon capture and small modular nuclear — to achieve almost all its emissions reductions shortly before hitting net-zero by 2050. Not only will emissions accumulate faster in the interim, but given the track record of high capital cost technologies that depend on government policy and/or financing support, there is a reasonable chance that these technologies will not be deployed on time, or at all, and emissions may therefore never come down. This is not something the federal government should accept as a replacement for Alberta's adherence to the Clean Electricity Regulations.

In addition to recalibrating its plans, Alberta must commit to stop disincentivizing low-cost and quick-to-deploy resources such as wind and solar that can deliver emissions reductions in the near term. This would involve removing or reducing a litany of obstacles the province has placed before those technologies in the last two and a half years. There is no credible plan to a net-zero Alberta grid by 2050 that does not include a return to widescale deployment of wind and solar.

The MOU negotiation and the future of clean electricity regulation in Alberta

In November 2025, the governments of Canada and Alberta signed a Memorandum of Understanding (MOU), under which the federal government indicated it would place the Clean Electricity Regulations (CER) "in abeyance" in Alberta, pending a negotiated agreement.[1]

The CER, published by the federal government in December 2024, drives the country to meet the growing demand for electricity with affordable, reliable and clean power, setting Canada on a path to a net-zero electricity sector by 2050.[2] In the MOU, both parties also affirmed their continued commitment to this mid-century electricity emissions target.

If Alberta is to live up to that commitment but prefers not to be subject to the CER, then during these MOU talks it must present an alternate plan that is credible. This should then form the basis of an equivalency agreement: a normal function of federal emissions policy, where provinces design and administer provincial regulations that are deemed, through a legal process, to be capable of achieving equivalent emissions outcomes as would have been achieved under the federal regulation.

In our view, a credible plan is one that incentivizes both short- and longer-term emissions reductions with a focus on pragmatism, no-regret solutions and quick wins. For Alberta, this should include:

a. Enabling the market to sustain deployment of affordable and commercially available low- and non-emitting electricity generation technologies (including by removing barriers to wind and solar) in the short and medium term, to meet growing energy needs.

b. Ongoing investments in grid modernization while pursuing transmission expansion. The province should maximize the use of existing transmission and distribution infrastructure first, while making the long-term plans and investments needed to grow the grid to enable the deployment of new generation capacity (supply) and large-scale electrification (demand).

[1] Prime Minister of Canada, "Canada-Alberta Memorandum of Understanding," November 27, 2025. https://www.pm.gc.ca/en/news/backgrounders/2025/11/27/canada-alberta-memorandum-understanding

[2] Government of Canada, "Canada's Clean Electricity Future." https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/clean-electricity.html

c. Hedging against the risk of overreliance on untested or early-stage technologies, such as natural gas abated with carbon capture and storage, hydrogen-fired turbines, or small modular nuclear. By focusing on the near-term deployment of renewables and supporting infrastructure (points a and b, above), Alberta will ensure electricity emissions continue to decrease. This spreads out the risk in case other early stage/untested technologies do not pan out as it currently hopes they will in the 2030s and beyond.

Finally, the plan presented must have a reasonable chance of achieving the same emissions reductions on the same timeline as would have been achieved under the CER (further detail in next section).

The crucial importance of cumulative emissions

There is existing precedent in the electricity sector for measuring environmental outcomes based on cumulative emissions.[3] Presenting a plan that simply achieves a similar final outcome of net-zero emissions just in time for 2050 is not enough; Alberta must achieve similar total emissions reductions over the next 24 years as it would have under the CER (see Figure 1 for an illustration of the impact of different pathways on cumulative emissions).

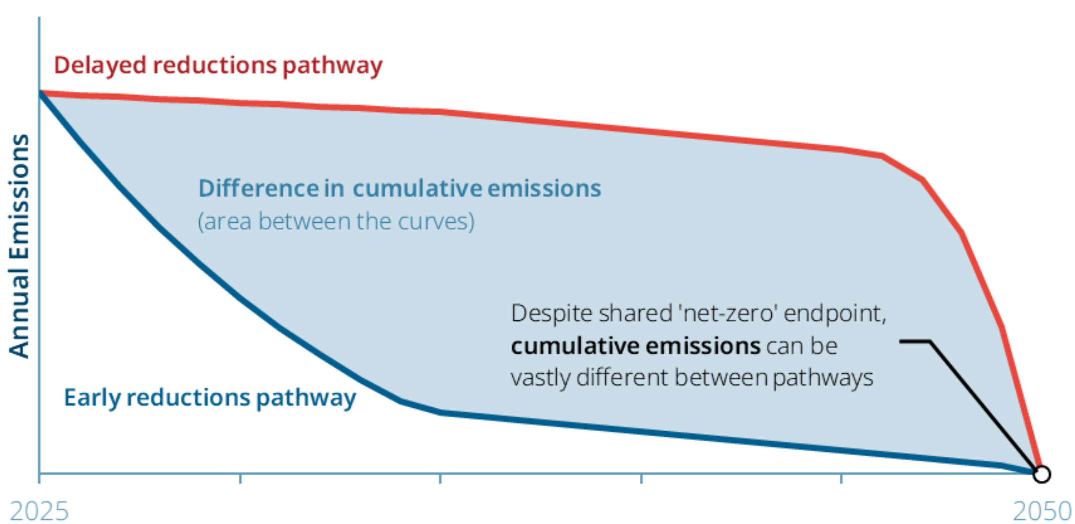

Figure 1. Illustration of annual and cumulative emissions difference between alternative net-zero pathways

[3] The coal equivalency agreements between the Government of Canada and the Governments of Nova Scotia and Saskatchewan both measure environmental outcomes based on cumulative emissions over time. For example, see Government of Canada, "Quantitative analysis of equivalency determination: coal-fired generation of electricity," 2024. https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/agreements/equivalency/canada-nova-scotia-greenhouse-gas-electricity-producers-2025/quantitative-analysis-equivalency-determination-carbon-dioxide-final.html

This matters for two reasons. Primarily, every tonne that is not emitted now will improve environmental outcomes. The government could quickly reduce the red tape it has introduced around non-emitting electricity generation, to deploy these technologies right away and see an immediate drop in emissions. In contrast, waiting until (and indeed *if*) technologies such as nuclear or gas with carbon capture are ready to be deployed commercially and at scale in Alberta would result in many more emissions being released into the atmosphere. The two plans could in theory reach the same target of net-zero by 2050, but the environmental implications are significantly different.

Secondly, shifting the mindset away from being guided solely by the goal of net-zero by 2050, and instead towards a plan of gradually reducing emissions over time to eventually reach that goal, will help Alberta's electricity industry, grid planners and regulators make forward-thinking decisions now that will pay dividends later. For example, accepting that wind and solar growth needs to return to a similar trajectory as it had in the early 2020s should lead to the building of more transmission, both within Alberta and to/from its neighbors, over the next five years. It should also lead to energy storage and demand-side measures to support the operations of Alberta's grid as more renewables are added.

State of Alberta’s renewable energy industry

Earlier this decade, Alberta led the country in wind, solar and energy storage installations, accounting for 5,800 megawatts (MW) of the total 6,800 MW of capacity added in Canada between 2020 and 2024.[4] However, for the last few years, prospective renewables developers in Alberta have suffered under prolonged policy uncertainty and, in some cases, the introduction of policies that amount to a hostile environment for the industry.

This began with the Government of Alberta’s widely publicized moratorium on renewable energy projects that was introduced in 2023, but also includes an array of other policy and market signals subsequently introduced by the province (outlined in Table 1).

The effect of this has been a significant drop in renewable developers’ sentiment in Alberta. The Pembina Institute has covered this phenomenon in depth in previous reports, largely relying on data from the Alberta Electric System Operator (AESO)’s project connection queue to ascertain the extent to which investor confidence was being dampened.[5] Since there is a lag between projects joining the queue, later being approved and eventually being built (or not), this was the best publicly available indicator available to analyze the impact of post-moratorium policies on the industry in real time (i.e. without waiting for installations to stall some years later). However, installation data now proves the real-world impact on investment.

New Alberta wind and solar has rapidly declined

Enough time has now passed since 2023 that we can see the impact not only in *prospective* projects choosing to take their investment out of Alberta, but in the shrinking levels of renewable capacity added to Alberta’s grid following the moratorium and other policy changes.

As Figure 2 shows, installations peaked in 2022 (the year before the moratorium) and have gradually declined since then. In 2025, less than one-fifth of new wind, solar and battery capacity installed in Canada was installed in Alberta — an exact reversal of the trend in the early 2020s, when four-fifths of renewables capacity added in Canada was installed in Alberta.[6] This

[4] Canadian Renewable Energy Association, “By the Numbers.” https://renewablesassociation.ca/by-the-numbers/

[5] Will Noel, Jason Wang and Scott MacDougall, *Down But Not Out: A brief status update on Alberta’s renewable energy industry* (Pembina Institute, 2025). https://www.pembina.org/pub/down-not-out

Will Noel, *Wind and solar projects in Alberta cancelled at an alarming rate* (Pembina Institute, 2025). https://www.pembina.org/pub/wind-solar-projects-alberta-cancelled-alarming-rate

[6] “By the Numbers.”

finding closely parallels that from a recent report by the Business Renewables Centre-Canada, noting the near-complete disappearance of corporate renewable energy deals in Alberta in 2025.[7]

It is unlikely that 2026 will be much better in terms of new installations. Only around 500 MW of solar and storage have received regulatory approvals with targeted installation dates this year.[8]

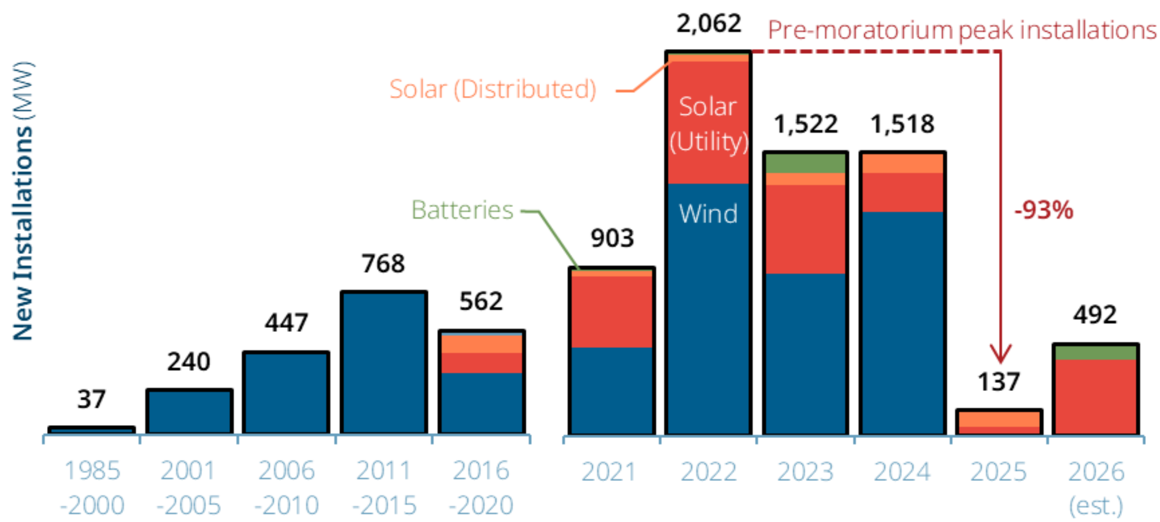

Figure 2. Alberta's installed wind, solar and battery capacity by installation year and estimated future installed capacity

2026 estimate based on system operator reporting.

Data sources: Alberta Electric System Operator and Alberta Utilities Commission[9]

[7] Business Renewables Centre-Canada, *2025 Renewables in Review* (2026), 4. https://businessrenewables.ca/system/files/2026-01/State%20of%20the%20Market%202025%20FINAL.pdf

[8] Alberta Electric System Operator (AESO), "Connection Project Reporting." https://www.aeso.ca/grid/transmission-projects/connection-project-reporting/

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

AESO, "Micro- and Small Distributed Generation Datafile," February 2026. https://www.aeso.ca/market/market-and-system-reporting/micro-and-small-distributed-generation-reporting/

AESO, "Wind and Solar Power Forecasting: Wind and solar actual vs forecast data." https://www.aeso.ca/grid/grid-planning/forecasting/wind-and-solar-power-forecasting/

AESO, "Long-term Adequacy Metrics – February 2026." https://www.aeso.ca/market/market-and-system-reporting/long-term-adequacy-metrics/

Alberta Utilities Commission, "Alberta Electric Energy Net Installed Capacity (MCR MW) by Resource." https://media.auc.ab.ca/prd-wp-uploads/Shared%20Documents/2023-InstalledCapacity.pdf

Growth of rooftop solar

It should be noted that 2025 was the first year since 2019 that distributed solar — mostly rooftop — saw more growth than utility-scale projects. As Figure 2 shows, distributed solar made up a significant portion of Alberta's renewables installations in 2025. The falling costs of solar installations, along with Alberta's microgeneration regulations, are leading more homeowners to recognize the affordability benefits. Distributed solar is an important resource and should be a key part of all grids, including Alberta's.

Nevertheless, if Alberta's renewables market were functioning healthily, we would still expect to see significantly more annual installations of utility-scale solar (and wind, and storage) than was installed in 2025. Overall, 2025 was still the lowest growth year for renewables and storage in Alberta since 2017.

Rooftop solar growth is a welcome development, but unless a significant acceleration in small-scale solar deployment in Alberta is achieved (as is being seen in other leading jurisdictions[10]), it alone will be unable to offset the loss of utility scale investment. For comparison, it would take around 15,000 residential rooftop installations, or 900 commercial rooftop installations, to match the annual generation of a single 100 MW solar farm.[11]

Renewables development faces extra barriers in Alberta

The regulatory and market barriers impacting renewable energy investment in Alberta are summarized in Table 1. Note some of the listed barriers, such as the proposed recycling program, are not inherently bad on their own. Rather, it is the layering of multiple policies, regulations and market changes, many of which have been introduced simultaneously, that adds up to an overall sense of hostility towards the sector.

Some of the policies (such as the land-use rules and reclamation security requirements) affect wind and solar only, whereas others (such as the Restructured Energy Market and Transmission Regulation updates) affect all electricity developers. However, as we elaborate in Table 1, in many cases policy or regulatory issues seem at risk of disproportionately disadvantaging

[10] For example, by the end of 2024, one out of every two houses in South Australia will have rooftop solar. Will Noel, Lia Codrington and Scott MacDougall, *I'll Have What They're Having: Lessons learned from six jurisdictions leading in wind and solar deployment* (Pembina Institute, 2024), 4-5. https://www.pembina.org/pub/what-theyre-having

[11] Assumes a lower capacity factor for distributed solar (15% instead of 20%), and an average installation size of 9 kW for residential and 150 kW for commercial.

renewables compared to other types of generation. Overall, this adds up to a policy approach that does not appear to be technology neutral.

There is no credible pathway to a net-zero grid in Alberta by 2050 that does not include sustained deployment of low-cost renewables in the near and medium term. Therefore, MOU negotiations must, in part, focus on how Alberta intends to reverse the trends noted above that are the consequence of the issues listed in the table below.

Barriers are presented in descending order of impact on renewables investment, with ranking based on our own engagement with industry, financial institutions, and other key stakeholders in the Alberta electricity ecosystem.

Table 1. Barriers to renewable energy investment in Alberta, in descending order of impact on renewables investment

Policy or regulatory issue	Description of change	Impact on renewables investment
Affect entire electricity sector		
Restructured energy market	Alberta is changing the way its electricity market operates. This includes shifting from a uniform price to location-based pricing, introducing new market-based reliability products, as well as raising/lowering the price cap/floor.	Changes would adversely impact the economics of wind and solar.[12] Financial institutions in Alberta also see the adverse impact the restructured market will have on renewable project financing.[13]
Transmission regulation	Forthcoming updates to the Transmission Regulation include shifting the cost of grid infrastructure from solely ratepayers to a combination of generators plus ratepayers and removing the zero-congestion requirement.[14]	Proposed updates will increase the cost of grid access for new power plants, especially wind and solar, while simultaneously increasing the frequency and volume of wind and solar curtailment.

[12] Energy and Environmental Economics, "Restructured Energy Market Report: Assessment of market outcomes & efficiency of the proposed REM design," March 14, 2025, 15-16. https://www.aesoengage.aeso.ca/42905/widgets/197800/documents/149190

Power Advisory, "Impact of REM on Renewable Generation," July 29, 2025, 8-11. https://aesoengage.aeso.ca/42905/widgets/197800/documents/156183

[13] Morison Park Advisors, "MPA Independent Assessment of the REM Design" 2025, 11. https://aesoengage.aeso.ca/42905/widgets/197800/documents/157270

[14] AESO, "Direction Letter from Minister," July 11, 2024. https://www.aeso.ca/assets/direction-letters/Direction-Ltr-from-Minister-REM_Tx-Policy_10Dec2024.pdf

Low emissions offset and credit prices	Emissions offsets are trading well below the headline carbon price of $95/tonne due to a surplus in the credit market. Proposed changes to the Technology Innovation and Emissions Reduction (TIER) system — allowing direct investment to offset emissions compliance obligations — would exacerbate the problem.[15]	Emissions offsets represent a significant revenue opportunity for renewables. If the TIER market were functioning properly in 2025, a renewables project could earn approximately $28/MWh from offsets, in addition to revenue from power purchase agreements or by selling to the grid. This compares to the average wholesale power price in Alberta in 2025 of $44/MWh.[16]
Electricity oversupply	In the past two years, growth in available electricity supply has been outpacing growth in demand.[17] This may soon change as large-scale electrification picks up, including the 1,200 MW of data centres with signed contracts.[18]	Current oversupply in Alberta's electricity market is delaying investment in generation, regardless of technology. But forward-looking power prices are rising,[19] likely due to demand growth forecasts, so investment signals should resume in the near term.
Affect renewables only		
Reclamation security	New reclamation security requirements for renewable energy developers in Alberta[20] are more expensive than those in 27 other jurisdictions.[21]	Wind and solar developers will be required to provide 30% of reclamation securities upfront, and 60% in year 15, effectively increasing the capital cost of the projects.
Agricultural land-use bans	New regulations limit renewable energy development on certain classes of agricultural lands, with minimal exceptions.[22]	Renewable projects (mostly solar) that are proposed on the classes of lands outlined in the regulations can either change their proposed location or demonstrate coexistence with agriculture, such as agrivoltaics.[23]

[15] Dave Sawyer, "Alberta's latest changes to industrial carbon pricing make MOU commitments harder to achieve," *Canadian Climate Institute,* December 5, 2025. https://climateinstitute.ca/news/albertas-latest-changes-to-industrial-carbon-pricing-make-mou-commitments-harder-to-achieve/

[16] "Annual Market Statistics Report."

[17] "Annual Market Statistics Report."

[18] AESO, "Large Load Projects." https://www.aeso.ca/grid/connecting-to-the-grid/large-load-projects/

[19] Alberta Market Surveillance Administrator, *Q5 2025 Quarterly Report* (2026), 88. https://www.albertamsa.ca/assets/Documents/Wholesale-Market-Report-Q4-2025.pdf

[20] Government of Alberta, "Restoring balance for Albertans," media release, December 6, 2024. https://www.alberta.ca/release.cfm?xID=9248925FBDA55-D371-7199-9A10C31A3D1D9270

[21] Business Renewables Centre Canada, *Reclamation Security: Comparative analysis* (2025), 3. https://businessrenewables.ca/sites/default/files/2025-06/BRC-Canada%202025%20Reclamation%20Security%20Report.pdf

[22] Government of Alberta, "Renewed path forward for renewable energy," media release, February 28, 2024. https://www.alberta.ca/release.cfm?xID=898196983D0FA-AECA-5F92-FF655CE1369C4E28

[23] Coexistence is considered successful if the crop or grazing land can maintain 80% of historic yield. Government of Alberta, "Guidelines to evaluate agricultural land for renewable generation," July 7, 2025, 5. https://open.alberta.ca/publications/guidelines-evaluate-agricultural-land-renewable-generation

No-go zones	New regulations ban development of new wind projects within 35 kilometres of protected areas or other "pristine viewscapes" as designated by the province.[24]	Wind projects that are proposed within the designated zones, apart from those on First Nations' land, must change their proposed location. It is unclear whether repowered projects (replacing aging-out turbines with newer models) will be granted exemptions.
Recycling fees	The province is developing requirements for an upfront recycling fee for wind and solar equipment but not for any other form of energy or electricity production.[25]	New wind and solar projects will face a modest increase in capital cost, amount still to be determined.

Investor confidence in Alberta's renewables has not recovered

Amidst a historically low year for new wind and solar installations, the outlook for future projects remains grim. Applications for new renewables saw a boom in 2023 during the first iteration of the AESO's new cluster application process, in which applications are accepted in batches, rather than one at a time.[26] But new proposals have fallen dramatically in the past two years. At the same time, cancelled applications continue to rise year over year, reaching nearly 10 GW in 2025 (Figure 3).

[24] Government of Alberta, "Pristine viewscapes and visual impact assessment zones," December 6, 2024. https://open.alberta.ca/publications/pristine-viewscapes-visual-impact-assessment-zones

[25] Government of Alberta, "Creating Canada's best recycling program," media release, August 13, 2024. https://www.alberta.ca/release.cfm?xID=90822FB35BB96-AAE0-1955-FDD28F87C9CADD40

[26] For a description of the cluster process, see our previous reports on this topic. For example: Will Noel, Jason Wang and Patrick Connolly, *Creating (Un)certainty for Renewable Projects: Review of the impact of Alberta's renewable energy moratorium one year later* (Pembina Institute, 2024), 12-13. https://www.pembina.org/pub/creating-uncertainty-renewable-projects

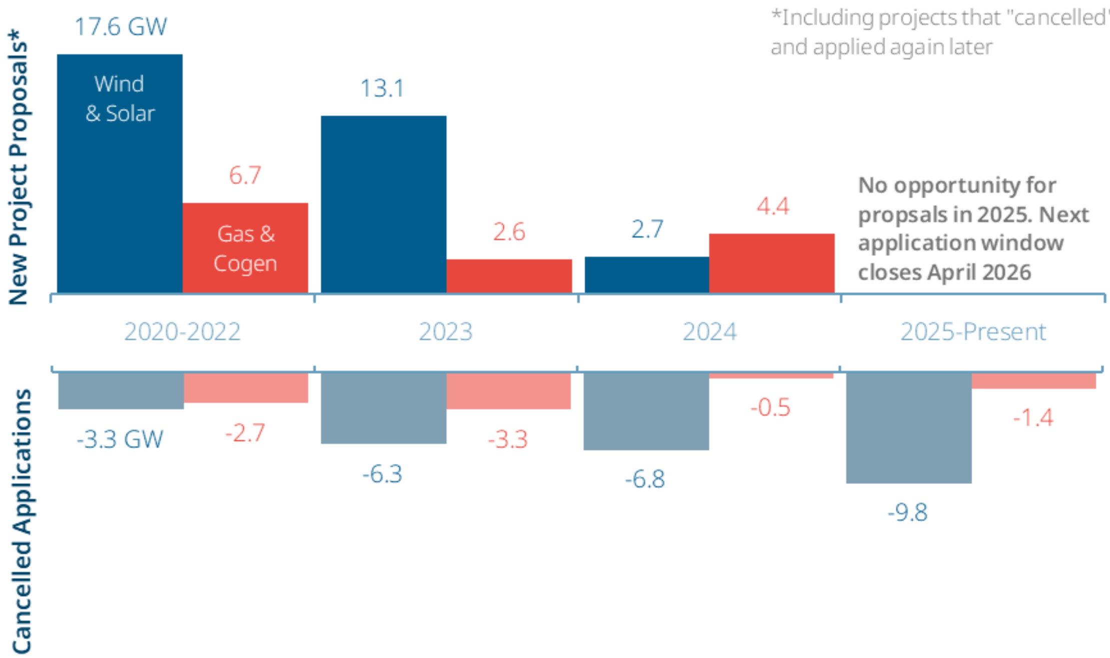

Figure 3. Project proposals and cancelled applications for new power plants in Alberta

Pembina Institute estimates based on Alberta Electric System Operator data[27]

As ever when assessing queue data, some level of cancellations is to be expected — not all projects make it all the way from joining the queue to being built, and this naturally happens for a host of reasons in all jurisdictions. However, Alberta is unique in that its renewables project development queue continues to empty faster than it is filling, leading to a net reduction in size for the second year in a row. As highlighted in our 2025 analysis, this is not something we are seeing in leading jurisdictions, such as in Texas and South Australia.[28]

In contrast, fossil fuel-based electricity projects are not seeing the same trends. In fact, the 2024 volume of new natural gas and cogeneration projects added to the queue was nearly double that of previous years, and more than wind and solar in the same year.

A new application window closing in April 2026 will bring a wave of new proposals (both renewables and natural gas).[29] As with previous clusters, applications will be a combination of brand new projects and others that the AESO has labelled as "cancelled" but which ultimately rejoin, effectively deferring their connection request.[30] In other words, it is conceivable that a portion of the 9.8 GW of renewables applications that were cancelled in 2025 (Figure 3) may flip

[27] "Connection Project Reporting."

[28] *Down But Not Out*, 6.

[29] AESO, "Cluster 3 Expected Timeline." https://www.aeso.ca/assets/cluster-3/Cluster-3-timeline.png

[30] These "cancelled" projects that rejoined under new clusters accounted for 3,843 MW in cluster 1 and 6,090 MW in cluster 2. *Down But Not Out*, 9.

to the positive side of the graph later this year. Nevertheless, there is nothing to suggest that the pattern shown in Figure 3, with renewables cancellations outweighing applications, will reverse without a suite of fundamental changes to address waning investor confidence. Cautious optimism is recommended.

Alberta's inadequate plan for emissions reductions

Risky bets over quicker, proven solutions

Between 2010 and 2023, Alberta lowered its electricity emissions by more than a third, from 51 to 33 megatonnes of carbon dioxide equivalent ($MtCO_2e$).[31] Most of these reductions came from phasing out coal power while increasing generation from wind and solar. However, Alberta remains the largest source of electricity emissions in Canada, generating approximately half of national emissions while representing less than one-fifth of supply.[32] With the final coal plant retirement in 2024, the province must now turn its attention to reducing emissions from natural gas-fired power.

In its Emissions Reduction and Energy Development Plan (EREDP, published in 2023), Alberta said it intends to reduce emissions from the electricity sector mainly by:

- "Diversification of low-emitting technologies… including [carbon capture and storage (CCS)], hydrogen and [small modular reactors]."
- "[Working] with consumers, industry and regulators… to support new technologies, including [energy] storage and demand-side management… [to support] emissions reductions."[33]

There are a couple of issues with this strategy:

- Fuel switching to hydrogen or installing CCS are both technologies that the AESO itself has labelled as "not yet commercially available" when critiquing the CER.[34] Reliance on such technologies risks a significant deficit in emissions reductions in the next five to 10 years, making compliance with a CER equivalency difficult, if not impossible.

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[31] Pembina Institute estimate, combining national inventory data with electricity emissions from cogeneration facilities. Environment and Climate Change Canada, *Canada's Official Greenhouse Gas Inventory (2025),* Table A13-10. https://data-donnees.az.ec.gc.ca/data/substances/monitor/canada-s-official-greenhouse-gas-inventory/C-Tables-Electricity-Canada-Provinces-Territories?lang=en

Alberta Environment and Parks, "Alberta Oil Sands Greenhouse Gas Emissions Intensity Analysis," 2025. https://open.alberta.ca/opendata/alberta-oil-sands-greenhouse-gas-emission-intensity-analysis#summary

[32] Pembina Institute estimate as above. *Canada's Official Greenhouse Gas Inventory (2025),* Table A13-1, A13-10.

"Alberta Oil Sands Greenhouse Gas Emissions Intensity Analysis."

[33] Government of Alberta, "Alberta Emissions Reduction and Energy Development Plan," 35. https://open.alberta.ca/publications/alberta-emissions-reduction-and-energy-development-plan

[34] AESO, "Clean Electricity Regulations." https://www.aeso.ca/future-of-electricity/clean-electricity-regulations/

- Wind and solar were not included as an opportunity for further emissions reductions in the EREDP. Rather, these technologies were labelled as a risk, requiring natural gas, hydrogen or nuclear backup to maintain system reliability, despite other jurisdictions with greater proportions of wind and solar than Alberta proving otherwise.[35]

The 2024 Long-term Outlook from the Alberta Electric System Operator models a 20-year pathway that closely resembles the above policy direction in the EREDP. As Figure 4 shows, three-quarters of the emission reductions that the AESO has modelled to 2040 are forecast to come from carbon capture and storage or use of hydrogen within natural gas plants, with remaining reductions coming from wind and solar displacing natural gas. Nuclear power is not modelled to lead to any emissions reductions over this period, as AESO forecasts include the first nuclear plant to come online in 2041.

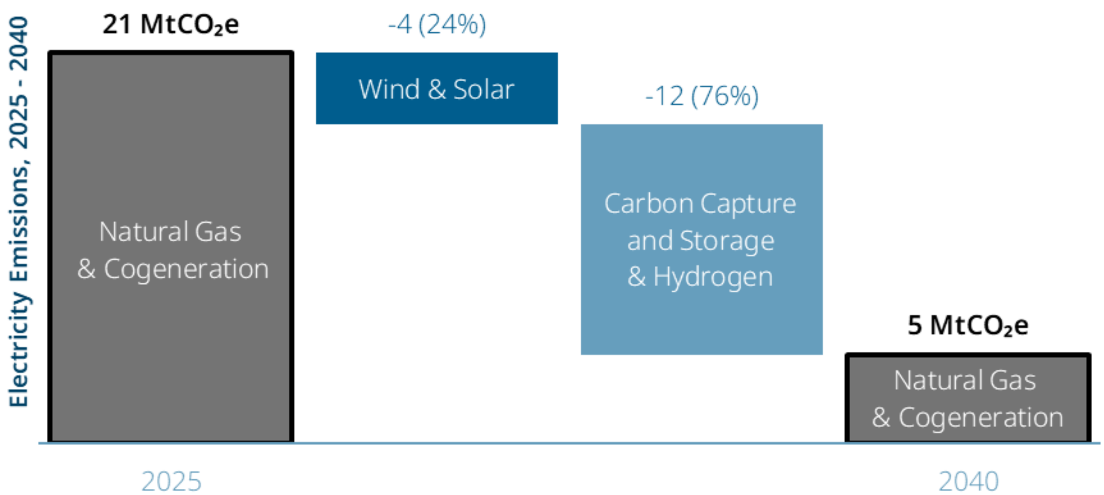

Figure 4. Alberta's current plan to reduce electricity emissions reductions, 2025 to 2040

Source: Pembina Institute analysis based on Alberta Electric System Operator data[36]

Figure 5 overlays AESO forecasts with historic (2015 to current) installed capacity of these technologies. The contrast between previous and current Long-term Outlooks, overlaid with actual installation data, highlights a few things:

a. The AESO's interpretation of Alberta's plan to reduce electricity emissions seems to rely heavily on relatively untested technologies that were not included in any of the previous Long-term Outlooks.

[35] "Alberta Emissions Reduction and Energy Development Plan," 32.

Jurisdictions leading in wind and solar development are instead relying on a suite of flexible resources for reliability, including gas, hydro, energy storage, interties and demand response. David Pickup, Gurprasad Gurumurthy and Scott MacDougall, *Powering ON: Examining Ontario's Integrated Energy Plan* (Pembina Institute, 2025), 14. https://www.pembina.org/pub/powering

[36] Includes electricity emissions from cogeneration, assuming an unabated emissions intensity of 200 tCO_2e/GWh. AESO, "2024 Long-Term Outlook."

b. Previous forecasts significantly underestimated the deployment of wind and solar, but it appears the opposite is now true: the 2024 Long-term Outlook is now apparently underestimating the myriad factors (discussed earlier in this report) that are already undermining actual deployment of wind and solar.
c. Without policy changes from Alberta to encourage the return of large-scale wind and solar investment, it is difficult to see how the projected deployment of those technologies — which until recently would have been considered bearish — could be achieved.

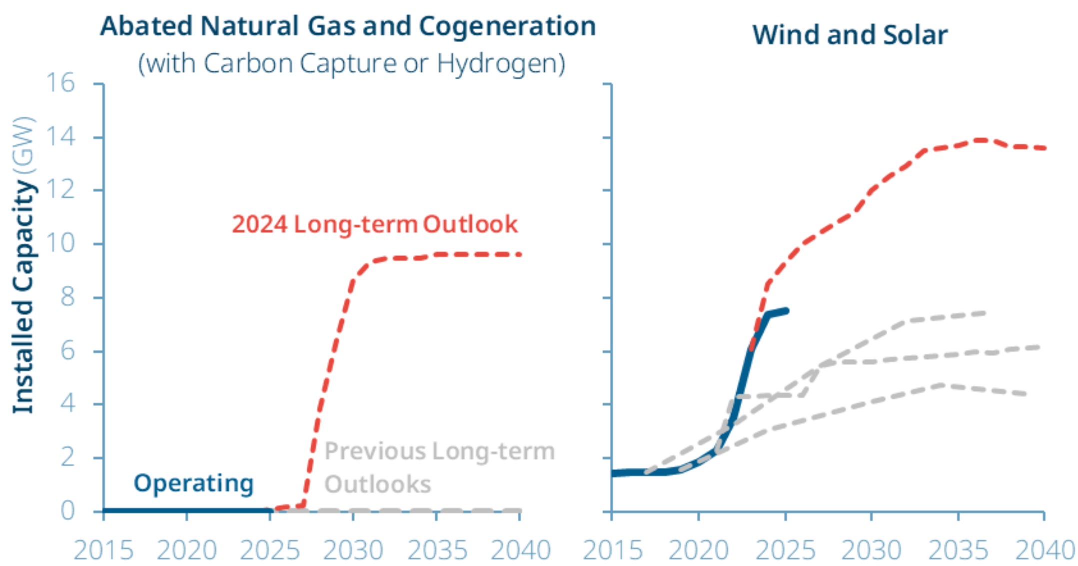

Figure 5. Operating and forecasted capacity of abated natural gas and cogeneration versus wind and solar

Data sources: Alberta Electric System Operator[37]

Alberta, and the AESO, are betting heavily on the rapid uptake of technologies (CCS and hydrogen) that would in theory allow the province to continue to use large amounts of natural gas for power, but with their emissions abated. As highlighted in the AESO's analysis, this is how the province intends to achieve the majority of electricity sector emissions reductions to 2040, with over 9,000 MW of existing natural gas and cogeneration facilities installing CCS between 2027 and 2032. However, as of February 2026, there are no known examples of commercially operational CCS facilities at utility-scale natural gas or cogeneration power plants. With the

37 "Annual Market Statistics Report."
AESO, "2017 Long-Term Outlook," 19. https://www.aeso.ca/assets/listedfiles/AESO-2017-Long-term-Outlook.pdf
AESO, "2019 Long-Term Outlook." https://www.aeso.ca/grid/grid-planning/forecasting/2019-long-term-outlook/
AESO, "2021 Long-Term Outlook." https://www.aeso.ca/grid/grid-planning/forecasting/2021-long-term-outlook/
AESO, "2024 Long-Term Outlook." https://www.aeso.ca/grid/grid-planning/forecasting/2024-long-term-outlook/

exception of one 15 MW facility under construction,[38] there are no concrete plans to develop any in Alberta for the foreseeable future.[39] In other words, both the Government of Alberta in its EREDP, and the AESO in its modelling, are relying on emissions reduction technologies that haven't historically delivered and that industry continues to be skeptical of. (Concerns around the viability of CCS deployment in this context are further highlighted in the section below on the limitations of carbon capture and storage for electricity generation.)

This overreliance results in policies and planning that hold back wind, solar and storage, the energy technologies that have been rapidly scaling up globally over the past five years. For example, continually underestimating the rate of wind and solar installations has contributed to insufficient transmission capacity and the congestion issues we see today in southeastern Alberta.

And yet, as mentioned above, the lack of actual deployment of CCS on power plants seems to have been a determining factor in AESO publicly stating that the technology is "not yet commercially available," leading the Government of Alberta to cite this as a reason why Alberta cannot meet stipulated emissions reductions under the CER. **If Alberta's goal, as it recommitted to in the recently signed MOU, is to achieve a net-zero electricity grid by 2050, then it must be expected as part of the CER equivalency agreement to make new plans that are not so heavily reliant on the very technologies that it said are not yet ready to help it meet CER emissions reductions.**

Limitations of carbon capture and storage for electricity

Emissions in some economic sectors are more difficult to abate through electrification and will likely require carbon capture (such as oilsands, cement, steel and petrochemicals production). However, several emissions-free electricity options are commercially available in the power sector, including energy efficiency, wind, solar, hydroelectric, geothermal and large-scale nuclear. Many of these technologies are also significantly cheaper and quicker to scale than outfitting natural gas or coal-fired power plants with CCS. It is therefore unsurprising that, despite decades of research and development, carbon capture and storage has not been deployed broadly in the electricity sector. In fact, **of the 98 CCS facilities proposed in the power**

[38] Entropy, "Onstream, commercial CCS at Glacier natural gas plant: World's first decarbonized gas plant through carbon capture, introducing clean power generation." https://www.entropyinc.com/glacier

[39] Most developers are not committing to abating the emissions at their proposed natural gas plants. Rather, they are simply labelling their projects as "CCS ready" or "having carbon capture optionality". For example, see the Kineticor Greenlight Electricity Centre: https://kineticor.ca/operation/greenlight-electricity-centre/

sector worldwide between 1972 and 2017, only two were actually installed, both on coal power plants, representing a success rate of only 2%.[40]

Since 2017, there has been a resurgence of interest in CCS for power generation globally, with a handful of coal, natural gas, and geothermal power plants now abating their emissions.[41] The total capture capacity of all electricity sector CCS plants is just under 3.5 $MtCO_2e$ per year — equivalent to 0.02% of global electricity emissions in 2024.[42] In Alberta, industry remains skeptical of CCS for electricity generation, with two of the seemingly more promising projects — retrofits at Genessee and Shepard combined cycle natural gas plants — being shelved, citing economic infeasibility.[43]

The economic case for CCS across sectors, including in power generation, can be significantly bolstered through a well-functioning industrial carbon pricing system. In the absence of an adequate carbon price and functioning credit market, operating CCS represents a pure cost; not only does it have its own operating and maintenance costs, but it also uses a portion of the electricity generated from the natural gas (or coal) plant it is connected to, known as a "parasitic load." If these facilities are not incentivized to abate their emissions through an industrial carbon pricing system — in which they can also offset the capital and operational cost of CCS by generating and selling emissions credits — then there is no clear business case for CCS to be built. This reinforces the need, elsewhere in the MOU negotiation, for Alberta and the federal government to achieve an outcome on Alberta's Technology Innovation and Emissions Reduction (TIER) regulation that significantly strengthens the system, which has recently been repeatedly undermined by regulatory changes made by the province.[44]

In addition, several groups have expressed their concerns with the technical feasibility of installing CCS on Alberta's existing cogeneration fleet in their feedback to the draft Clean Electricity Regulations. For example, Electricity Canada noted that there were "no known examples of installing [CCS] on a cogeneration facility," and that "it is not clear that it is feasible

[40] Tsimajei Kazlou, Aleh Cherp and Jessica Jewell, "Feasible deployment of carbon capture and storage and the requirements of climate targets," *Nature Climate Change* 14, no. 10, Supplementary Table 1. https://doi.org/10.1038/s41558-024-02104-0

[41] Global CCS Institute, *Global Status of CCS* (2025), 44-46. https://www.globalccsinstitute.com/wp-content/uploads/2025/10/Global-Status-of-CCS-2025-report-9-October.pdf

[42] Ember, "Electricity Data Explorer." https://ember-energy.org/data/electricity-data-explorer/

[43] Global News, "Capital Power pulls plug on proposed $2.4B Genesee carbon capture and storage project," May 1, 2024. https://globalnews.ca/news/10463652/capital-power-genesee-carbon-capture/

ENMAX, "ENMAX and Capital Power complete evaluation of CCS technical study for Shepard Energy Centre," July 19, 2024. https://www.enmax.com/news/enmax-and-capital-power-complete-evaluation-of-ccs-technical-study-for-shepard-energy-centre

[44] "Alberta's latest changes to industrial carbon pricing make MOU commitments harder to achieve."

to do so."[45] TC Energy had similar concerns, noting the physical barriers associated with deploying CCS at cogeneration sites, such as the already limited space in industrial parks that cannot accommodate any additional equipment, and issues with access to supplementary resources (water) or infrastructure (CO_2 pipelines) required to operate the CCS process.[46]

Carbon capture is unlikely to deliver in the short term

The AESO 2024 Long-term Outlook forecasts a future in which the majority of cogeneration and combined cycle natural gas plants are outfitted with CCS by 2032. If all CCS installations occur in the timeline outlined in the Long-term Outlook, assuming a carbon capture rate of ~90%, cumulative electricity emissions in Alberta over the next 24 years will be on the order of 171 $MtCO_2e$, which can be used as a benchmark to which alternative decarbonization plans could be compared to (e.g. one that includes the CER).[47]

However, given that no projects are currently moving forward, it is worth examining a scenario where some CCS projects do not reach a final investment decision (FID), due to some combination of economic, technical, or site-specific constraints, such as a lack of available space. And, given that nuclear development timelines are both long and uncertain, it is unlikely that an Alberta-based nuclear power plant will be installed pre-2040, meaning it would be unable to contribute to emissions reductions before then.[48]

Figure 6 shows the cumulative emissions projections of the AESO 2024 Long-term Outlook under a range of potential installation outcomes of CCS facilities, relative to the 171 $MtCO_2e$ by 2050 benchmark. Results of this analysis show a range of cumulative emissions outcomes that already exceed the benchmark in just a few years (between 2034 and 2039), resulting in total emissions 1.5 to 2.4-times that of the benchmark by mid-century. This shows **there is significant risk that Alberta's electricity decarbonization plan is over-promising and will ultimately under-deliver.**

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[45] Electricity Canada, *Clean Electricity Regulations* (2023), 16. https://www.electricity.ca/files/reports/Final-Electricity-Canada-CER-Response.pdf

[46] Government of Canada, "Clean Electricity Regulations," Canada Gazette Part I, 157, no. 33, August 19, 2023. https://gazette.gc.ca/rp-pr/p1/2023/2023-08-19/html/reg1-eng.html

[47] AESO, *Emerging Technology Drivers: AESO 2024 Long-Term Outlook* (2024), 5-8. https://www.aeso.ca/assets/Uploads/grid/lto/2024/2024-LTO-Emerging-Technology-Drivers.pdf

Estimate includes electricity emissions from cogeneration, assuming an unabated emissions intensity of 200 tCO_2e/GWh.

[48] *Powering ON*, 7-8.

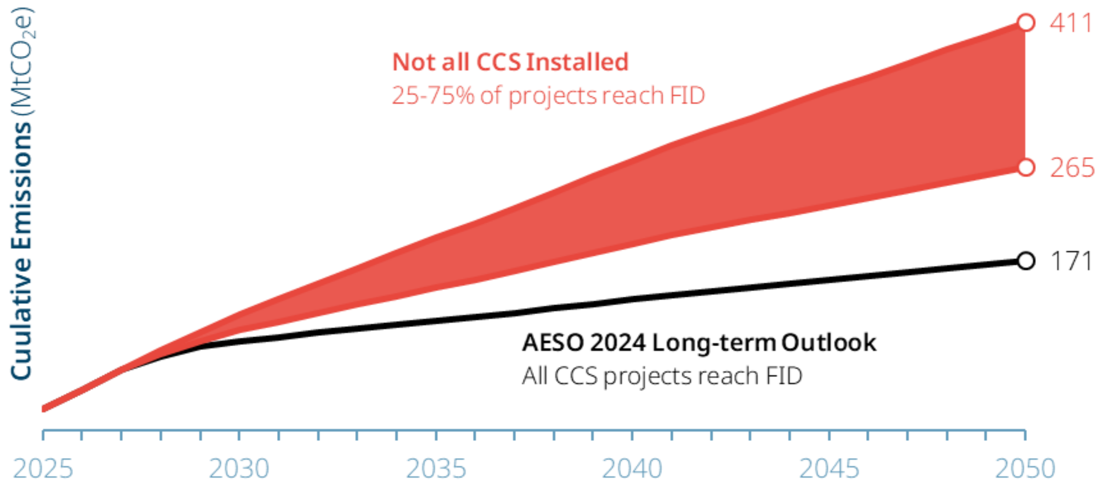

Figure 6. Cumulative emissions impacts if carbon capture and storage falls short of expectations

Source: Pembina Institute analysis based on Alberta Electric System Operator data[49]

As part of the MOU negotiation and for the CER to be placed into "abeyance," Alberta must demonstrate how it will achieve equivalent emissions outcomes as it would have under the CER. Clearly, then, it must plan for a scenario in which CCS does not deliver in the short term. Given the long development timelines for nuclear and lack of viable sites for new hydroelectric facilities, the only commercially available options in the required timeframe are wind and solar.

49 "2024 Long-Term Outlook."

Clean electricity takeaways for equivalency

The MOU indicated that the federal government was willing to place the Clean Electricity Regulations “in abeyance” in Alberta, pending a negotiated agreement. We support Alberta’s right to strike an equivalency agreement on this matter — but any plan that Alberta presents for its electricity emissions during the MOU negotiation must be rigorously assessed to ensure both that it is credible (i.e. based on pathways and technologies with reasonable likelihoods of deployment) and that it meets the legal threshold of achieving the same cumulative emissions outcomes on the same timeline.

Saving up the bulk of emissions reductions to the later 2030s and 2040s through CCS, hydrogen and nuclear does not just present risk in terms of meeting the actual final target (net-zero by 2050) on time given the relative untested nature of those technologies in Alberta; it also results in many more emissions entering the atmosphere in the preceding years as would have if Alberta had opted for a larger proportion of quicker-to-scale renewable energy. The assumption that natural gas abatement will lead to rapid, short-term emission reductions, despite significant industry skepticism, and that nuclear will deliver a net-zero electricity system by 2050, despite a lack of industry, government, regulator, and system operator experience, is not a credible plan.

To set itself up for success, and demonstrate good faith in the ongoing negotiations with the federal government, Alberta should take the following steps:

- **Commit to achieving equivalent emissions reductions as it would have under the CER on a cumulative basis.** Simply reaching net-zero just in time for 2050 is not enough, if all the emissions reductions occur in the final hour. Consistent annual reductions in electricity emissions over the next quarter century will ensure environmental goals are not achieved at the expense of consumer affordability or system reliability.
- **Demonstrate, through modelling and analysis, a reasonable path toward electricity decarbonization by mid-century.** The AESO publishes a Long-term Outlook on a two-year cycle, meaning the next forecast is expected to be released later this year.[50] The next forecast needs to present a more pragmatic view on the future of electricity in Alberta, rather than relying on expensive, unproven technologies.

[50] AESO, “Forecasting.” https://www.aeso.ca/grid/grid-planning/forecasting/

- **Update the Emissions Reduction and Energy Development Plan to parallel the new modelling pathways.** It appears the current EREDP was used to guide the modelling presented in the 2024 AESO Long-term Outlook, with an oversized emphasis on gas-fired power with CCS. The next iteration needs to be reversed, with pragmatic modelling guiding the plan.
- **Restore a business-friendly and supportive regulatory environment for clean energy investment.** As Canada looks to grow its supply of clean electricity, Alberta is actively chasing away investment in clean energy resources. Meanwhile, other provinces and territories have opened the door for development, calling for clean, affordable electricity to meet growing demand.

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