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Zeroing In

Pathways to an affordable net-zero grid in Alberta

Will Noel and Binnu Jeyakumar

June 2023

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The Pembina Institute is a national non-partisan think tank that advocates for strong, effective policies to support Canada's clean energy transition. We employ multi-faceted and highly collaborative approaches to change. Producing credible, evidence-based research and analysis, we consult directly with organizations to design and implement clean energy solutions, and convene diverse sets of stakeholders to identify and move toward common solutions.

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Executive summary

Alberta is at a crucial inflection point in the evolution of its electricity grid. By the end of this year, it will have successfully phased out coal-fired generation six years ahead of schedule. At the same time, it is rapidly expanding its renewable fleet, building more wind and solar than the rest of Canada. There has also been an increase in electric vehicle usage and rooftop solar among other consumer-driven clean energy behaviours. Investors and corporations are also seeking to invest in jurisdictions that can help meet their clean electricity goals. The province and the various private sector entities involved in electricity generation, transmission and distribution need to make significant investments in the electricity grid to keep pace with these trends. The decisions made today regarding these investments will dictate the configuration and affordability of Alberta's grid for decades to come.

Canada and the U.S. (along with other G7 countries such as the U.K. and Germany) have committed to net-zero or clean grids by 2035. These goals are being driven by the fact that a net-zero electricity grid is fundamental to a net-zero economy, where economy-wide decarbonization will largely be achieved through broad electrification. Alberta will need to decarbonize its grid to remain competitive with its neighbours and peer jurisdictions.

A net-zero emission electricity grid is one that will generate and supply electricity without adding greenhouse gas emissions into the atmosphere. This is achieved through scaling up non-emitting energy such as wind and solar; deploying energy storage to improve grid flexibility; enabling demand-side measures to decrease electricity consumption during peak hours; and ensuring that fossil fuel generation is equipped with carbon capture and storage technology (i.e. abated). It may also require limited use of carbon removals to account for emissions from any remaining unabated generation.

There are several paths through which Alberta could decarbonize its electricity grid in an affordable and reliable manner. The Pembina Institute partnered with the University of Alberta to model a number of different pathways. In this report, we examine six decarbonization scenarios compared to the latest Long-term Outlook (LTO) analysis by the Alberta Electric System Operator (AESO).

Key findings

- **A decarbonized electricity grid reduces costs for Albertans.** All our analyses, including the most ambitious decarbonization scenarios, result in total electricity system costs that are lower than those predicted by the AESO Net-Zero Emissions Pathways report (Figure 1). In fact, all scenarios result in lower costs than the AESO's 2021 Long-term Outlook *Reference Case*, used as a base case in their net-zero analysis. These cost reductions would be increased further through the various federal incentives and investments, and by accounting for the cost of addressing residual emissions through carbon removal activities, both of which were not included in our modelling. Between 2023 and 2035, our baseline scenario would cost $22 billion less than the AESO 2021 LTO *Reference Case* and $27–28 billion less than their net-zero scenarios.[1] Cost reductions are driven by a rapid deployment of low-cost wind and solar, which displaces large amounts of existing natural gas generation. This also reduces the need for significant expansion of the natural gas fleet, avoiding the volatile costs of gas as a fuel. This transformation would also help reduce household electricity costs for Albertans, as wind and solar lower the price of power.

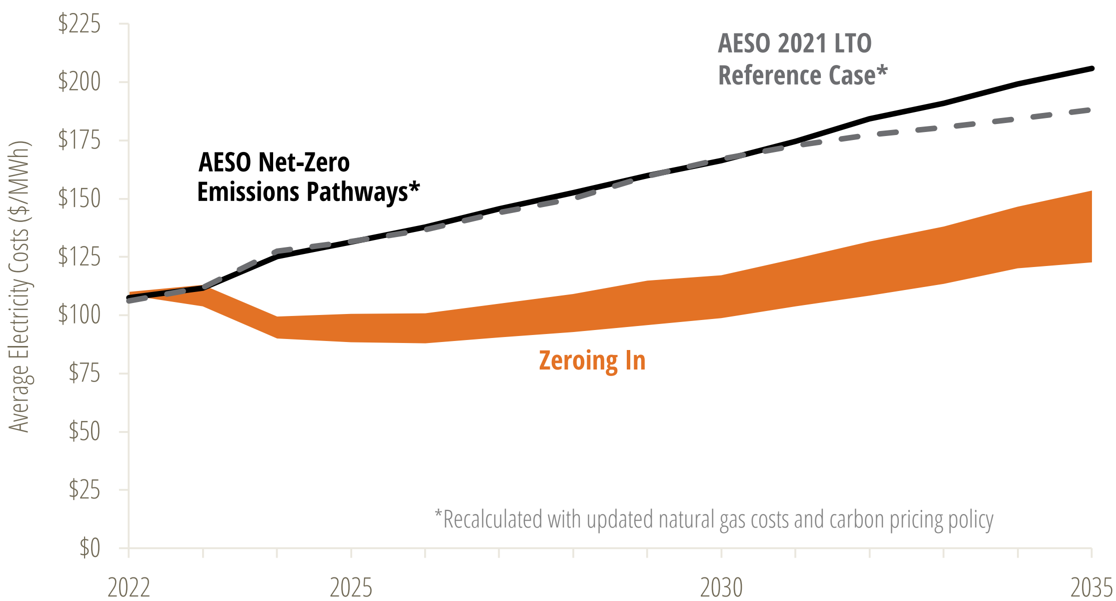


Figure 1. Comparison of modelled annual electricity system costs with previous AESO analyses

- **Expanding transmission interconnections and storage capacity results in significant cost reductions and increases electricity exports from Alberta.**

[1] Costs in AESO scenarios were recalculated with updated natural gas prices and carbon pricing policy.

Interties and energy storage can decrease system costs through improving the utilization of existing renewable energy assets and reducing the need to expand Alberta's generating fleet. Expanding the interties would also significantly reduce the need for new abated natural gas generation to meet peak-winter demand during low-wind hours. Additionally, all scenarios show Alberta — which historically and currently imports more electricity than it exports — as a net exporter of clean electricity, with exports increasing with renewable and intertie capacities. This creates an attractive energy export opportunity for Alberta.

- **Renewable energy becomes the dominant source of electricity generation and unabated natural gas capacity decreases.** By 2035, renewable energy is the largest source of electricity generation in all six of our scenarios (Figure 2), serving 45–58% of Alberta's total electricity demand and up to 71% of grid-connected generation. Our modelling — which optimizes for costs while ensuring the grid remains reliable — shows Alberta's 2035 wind fleet expanding to three to five times larger than its current installed capacity. At the same time, it shows installed solar capacity increasing by two to four times. Most scenarios also result in the installation of new natural gas generation outfitted with carbon capture technologies and a decrease in unabated natural gas capacity.

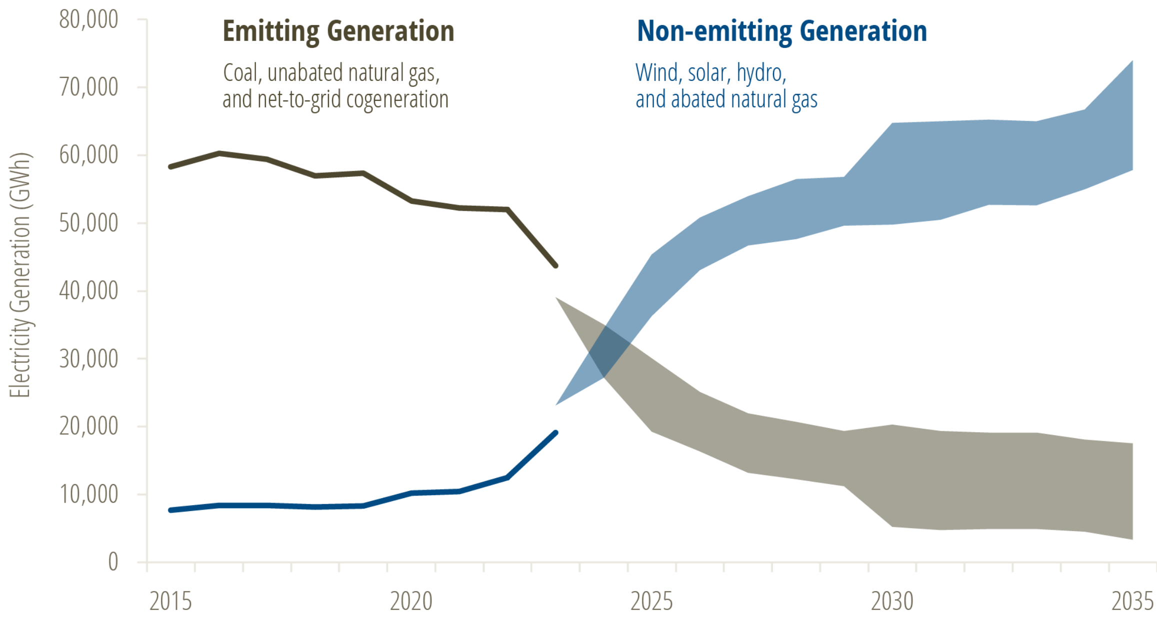


Figure 2. Historical electricity generation (2015–2023) with modelled range to 2035

Gap in 2023 is due to modelling uncertainty (e.g. electricity demand and weather forecasts)

- **A proactive approach with well-designed policies can help reduce household costs while lowering emissions.** Our analyses show a significant decrease in emissions in all scenarios. Electricity emissions would decrease by between 71% and 93% relative to 2021 (with emissions from behind-the-fence cogeneration excluded). Electricity costs for households and total electricity system costs can be reduced by taking a thoughtful and portfolio approach to policies and government support.

- **Additional policy measures are needed to reduce emissions from behind-the-fence generation at industrial cogeneration facilities.** As most electricity sector policies (including the Clean Electricity Regulations and TIER for electricity) do not consider emissions from the electricity generated and consumed behind the fence, it is critical that there are separate policies specific to emissions reductions in the oil and gas sector.
- **Alberta's electricity grid has already decarbonized faster than anyone anticipated.** In 2015, the Alberta government announced plans to phase out coal by 2030. Alberta's grid is now on track to be off coal by the end of 2023, six years ahead of schedule. At the time of this commitment many commentators said a coal phase-out was not feasible. Alberta's current generation mix shows that the pace of the phase-out and clean energy development has exceeded even the more ambitious scenarios in the Pembina Institute's previous two analyses (in 2009 and 2014) of grid decarbonization in Alberta.

Recommendations

To maximize the benefits of achieving a net-zero electricity grid, the Pembina Institute recommends the following:

1. **Commit to a provincial net-zero grid by 2035 and develop a made-in-Alberta plan.** Economic competitiveness will increasingly be tied to a clean electricity grid. A government commitment to achieving provincial net-zero electricity by 2035 will provide policy certainty to generators and attract investment to Alberta. This includes maintaining carbon pricing and lowering the electricity high-performance benchmark to zero by 2035.
2. **Enable the continued deployment of low-cost proven technologies such as renewable energy, battery storage, and demand-side measures.** Wind, solar, battery storage, demand response, and energy efficiency are the most cost-effective solutions for a reliable electricity grid. Government support, both financial and through enabling policies and regulations, for these technologies will accelerate the transformation. Support is also needed to de-risk urgent, strategic investments in abated natural gas generation and longer-term energy storage to help push Alberta to near-zero electricity emissions by 2035. However, overdependence on carbon

capture technologies in the electricity sector could inflate costs, prolong emissions from fossil fuel generators and divert resources from other sectors that are more difficult to decarbonize (e.g. steel and cement manufacturing).

3. **Facilitate provincial cooperation on interties**. Interties reduce system operating costs while providing grid reliability services between jurisdictions, especially those with different electricity generation mixes. Increased intertie capacity would also allow Alberta to establish itself as a net exporter of clean electricity. Collaboration between provincial (and U.S. state) governments and financial support from the federal government is needed to enable these large inter-jurisdictional infrastructure projects to proceed.
4. **Maintain federal policy certainty by developing and implementing a robust Clean Electricity Regulation (CER) and enhancing industrial carbon pricing.** To be effective in helping Canada achieve its decarbonization goals, the federal government needs to ensure the CER is ambitious and stringent enough to encourage clean energy investments. The federal output-based carbon pricing system for electricity should lower its benchmark to zero and provide a schedule of increasing carbon price after 2030.
5. **Ensure equitable opportunity through developing a net-zero grid.** The development of a net-zero grid will require a large capacity of skilled labour and expertise and can usher in greater local economic development. Governments can enable equitable participation across various communities and the workforce, with access to permanent, good-paying employment with opportunities for advancement, particularly for those who are currently facing systemic inequalities that continue in the Canadian energy sector.

1. Introduction

Alberta is at a crucial inflection point in the evolution of its electrical grid. By the end of this year, it will have successfully phased out coal-fired generation, which was the dominant source of electricity just six years ago. At the same time, it is rapidly expanding its renewable fleet, building more wind and solar than the rest of Canada.[2] There has also been an increase in electric vehicle usage and rooftop solar, among other consumer-driven clean energy behaviours. The province and the various private sector entities involved in electricity generation, transmission and distribution need to make significant investments in the electricity grid to keep pace with these trends. The decisions made today regarding these investments will dictate the configuration of Alberta's grid for decades to come.

At the same time, Canada and the U.S. have committed to net-zero or clean grids by 2035. Investors and corporations are seeking to invest in jurisdictions that can help meet their clean electricity goals. This is critical for understanding how Alberta can achieve a net-zero electricity grid by 2035 in a reliable and affordable manner.

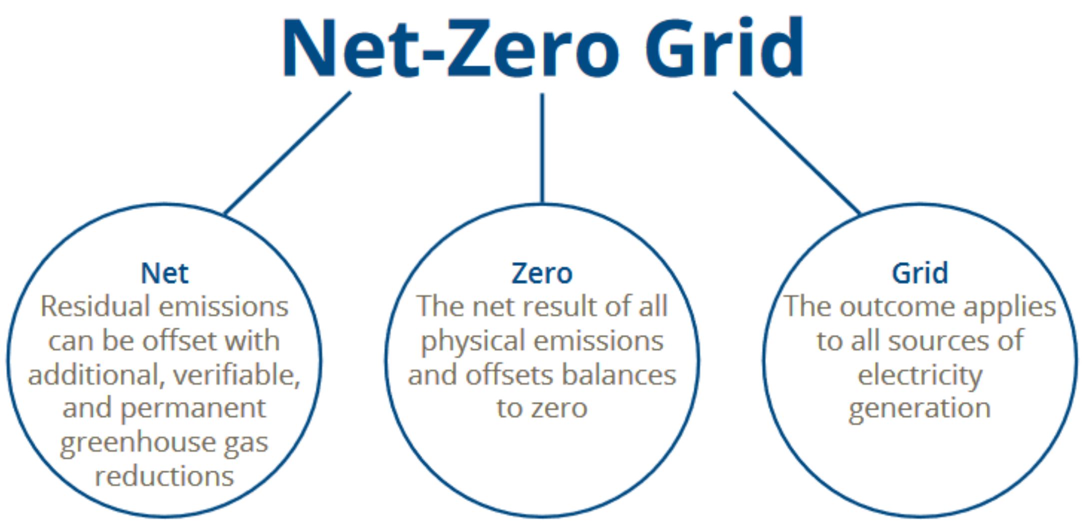
1.1 What is a net-zero grid?

A net-zero grid will generate and supply electricity with no greenhouse gases released into the atmosphere. It should use as much non-emitting technologies as possible, although it may allow for some low-emitting generation only if proper offset requirements are in place.[3] The *Canada Net-Zero Emissions Accountability Act* articulates this principle of "netting" as "… anthropogenic emissions of greenhouse gases (GHG) [released] into the atmosphere…" must be "… balanced by anthropogenic removals of greenhouse gases."[4] This definition should be applied to all sources of electricity generation.

[2] Canadian Renewable Energy Association, "Renewable Project Data: General," (2022). https://renewablesassociation.ca/wp-content/uploads/2022/01/CanREA-Renewable-Project-Data-General-2022-01.pdf

[3] Binnu Jeyakumar, *Achieving A Net-Zero Canadian Electricity Grid by 2035: Principles, benefits, pathways* (Pembina Institute, 2023), 1. https://www.pembina.org/pub/achieving-net-zero-canadian-electricity-grid-2035

[4] Government of Canada, *Canada Net-Zero Emissions Accountability Act* 2021, S.C., c. 22. https://laws-lois.justice.gc.ca/eng/acts/c-19.3/fulltext.html



Achieving net-zero in Alberta will require a diverse mix of non-emitting energy and energy storage technologies, demand-side solutions, energy efficiency, and grid infrastructure.

A note about cogeneration

Nearly two-fifths of electricity generated in Alberta (39% in 2022) is from natural gas cogeneration facilities whose primary function is to serve the heat and electricity demand of oilsands production processes. While the majority (around 59%) of that cogeneration is produced and consumed "behind-the-fence" (i.e. in oilsands production processes) by the operating facilities themselves, the balance (41% of cogeneration, representing 16% of all generation in Alberta) is exported to the interconnected electricity system (the “grid”). However, as the operation of these facilities is influenced by economic factors outside the electricity market (e.g. oil prices and minimum loads on oil production equipment), electricity market models must make simplifying assumptions regarding their behaviour. Emissions from these facilities — associated with both behind-the-fence generation and consumption, and net-to-grid generation — cannot be ignored and should be addressed through a suite of policy measures.

1.2 Why is a net-zero grid important in Alberta?

Reaching net-zero will provide economic, social, and environmental benefits to Albertans. These benefits should be understood and incorporated when assessing the socioeconomic impacts of net-zero policies in general and any net-zero outcome scenario in particular.

Jobs and economic development

Investments in grid infrastructure, renewable energy, and energy storage will create jobs and drive economic development in Canada. As the grid is decarbonized, job growth in the clean energy economy will outpace the losses from the fossil fuel industry. In fact, according to Clean Energy Canada, a net-zero economy would drive 10% growth in employment for Alberta's clean energy sector, significantly outpacing the decline in the fossil fuel industry.[5]

Competitiveness and investment attraction

Investors, creditors, and customers are becoming increasingly aware of businesses' climate impacts, holding them to higher standards of action to reduce climate and carbon risk. These environmental, social and governance (ESG) factors are driving major global companies to allocate capital investment to jurisdictions with low-carbon grids to mitigate their carbon risk exposure.[6]

Affordability

A net-zero grid will protect consumers from the volatility of fossil fuel prices while leveraging the cheapest sources of energy and energy storage: wind and solar, and increasingly batteries. As evidenced in recent years, despite Alberta having a wealth of natural gas resources, the price of gas can be volatile depending on the state of global commodity markets. Reducing reliance on fossil fuels will decouple the price of electricity from global fossil fuel markets and will help provide stability to consumer utility bills. At the same time, the cost of new clean energy technologies continues to decline. Between 2009 and 2021, the levelized cost of utility-scale wind and solar generation fell by 72% and 90% respectively and, in Alberta and Ontario, new renewable projects are now cost-competitive with natural gas power plants, even without carbon pricing.[7,8]

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[5] Clean Energy Canada, *A Pivotal Moment* (2023), 4. https://cleanenergycanada.org/report/a-pivotal-moment/

[6] Dale Beugin and Michael Gullo, "Clean electricity is a must-have for business — and for Canada's economic prosperity," *Canadian Climate Institute*, July 21, 2022. https://climateinstitute.ca/clean-electricity-is-a-must-have-for-business/

[7] Lazard, *Levelized Cost of Energy Analysis: Version 15.0 (*2021), 9. https://www.lazard.com/perspective/levelized-cost-of-energy-levelized-cost-of-storage-and-levelized-cost-of-hydrogen/

[8] Clean Energy Canada, *A Renewables Powerhouse (*2023), 1. https://cleanenergycanada.org/report/a-renewables-powerhouse/

Electricity prices in Alberta are mainly set by a handful of companies that manage the vast majority of price-setting supply. These companies are able to increase their markups and overall profit margins during periods of tight supply — which has led to recent electricity price increases. By introducing new market participants, weakening the control held by any single or small set of generators, and introducing additional zero-marginal-cost generation to the grid, the route to net-zero will see more competitive market outcomes, benefiting consumers.

Economy-wide decarbonization

A clean grid is essential for achieving emissions reductions in other economic sectors such as buildings, transportation, and industry, as these sectors seek emissions reductions through electrification. Alberta's recently announced Emissions Reduction and Energy Development Plan has an "aspiration to achieve a carbon neutral economy by 2050, and to do so without compromising affordable, reliable and secure energy for Albertans, Canadians and the world." Meanwhile, the federal government has a legislated commitment to reaching net-zero emissions by 2050.

Achieving a net-zero electricity grid by 2035 is key to achieving these economy-wide decarbonization goals. A clean grid will not only help reduce electricity sector emissions but also accelerate emissions reductions across various sectors of the economy by way of electrification.[9] For example, all passenger vehicles sold by 2035 need to have zero operating emissions under the proposed federal regulated sales target. Therefore, a net-zero electricity grid will be essential to provide the necessary energy to achieve this and will concurrently reduce emissions from the transportation sector.[10] Because non-emitting energy options are readily available in the electricity sector and because other sectors with limited or more costly decarbonization options will look to electricity to achieve net-zero outcomes, electricity will be key for any feasible 2050 net-zero economy.

[9] Economy-wide emission reductions led by a net-zero grid will also help reduce emissions intensity of manufactured and exported goods and strengthen Canada's economy and trade against environmental trade policies such as carbon border adjustments.

[10] Environment and Climate Change Canada, "Proposed regulated sales target for zero-emissions vehicles," 2022. https://www.canada.ca/en/environment-climate-change/news/2022/12/proposed-regulated-sales-targets-for-zero-emission-vehicles.html

Equity

A net-zero grid could help in addressing the systemic inequalities that exist in the Canadian energy sector. Governments can enable equitable participation with access to permanent, good-paying employment, with opportunities for advancement, particularly for women, racialized, newcomers, First Nations, Métis, and Inuit peoples.[11] Research from Electricity Human Resources Canada shows that currently, "the [electricity] sector is only 26% women, 5% Indigenous people, 5% workers under 25, and 3% persons with disabilities."[12] All government investment in a net-zero electricity grid should do double duty to advance equity and address systemic inequalities by ensuring equitable access to jobs, training and supports that enable all Canadians the opportunity to participate in the clean economy.

Federal programs

In addition to the above inherent benefits and opportunities of a net-zero grid for Alberta, the federal government is also actively pursuing several policies and incentives to require and enable net-zero emissions grids across Canada. Alberta can capitalize on these federal investment signals and supports by charting its own course for a decarbonized grid by 2035. Specifically, the federal government is:

- Designing Clean Electricity Regulations (CER) – As proposed in the draft regulations, an emissions intensity standard will be applied to existing electricity generation assets that are beyond their end of prescribed life (EoPL) and to assets built after 2025.[13] The standard will eventually prevent new unabated gas-fired generation (that is, generation from plants that do not use carbon capture technologies to reduce emissions) and may accelerate the retirement or retrofitting of existing unabated gas-fired generation.
- Introducing tax incentives and targeted funding – The 2023 federal budget introduces several investment incentives for clean energy and clean energy

[11] Grace Brown and Binnu Jeyakumar, *Supporting Workers and Communities in a Coal Phase-out: Lessons learned from just transition efforts in Canada* (Pembina Institute, 2022), 40. https://www.pembina.org/pub/supporting-workers-and-communities-coal-phase-out

[12] Electricity Human Resources Canada, "Workplace Solutions: Diversity & Inclusion." https://electricityhr.ca/workplace-solutions/

[13] Government of Canada, "Proposed Frame for the Clean Electricity Regulations," 2022. https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/publications/proposed-frame-clean-electricity-regulations.html

manufacturing, as well as funding for programs to support grid modernization and transition.[14]

- Pursuing regional energy and resource roundtables – These are pathways for the federal government to identify region-specific opportunities for partnership to accelerate clean transformation of traditional industries and support emerging ones.

Alberta can leverage these policies and programs to further enable the affordability, competitiveness, and investment attractiveness of a clear trajectory toward a net-zero grid.

The trends and opportunities identified in this section illustrate that this is a critical moment for Alberta to start planning for a concerted transition to a net-zero grid. In the following section, we explore the ongoing advances towards a clean grid that are already happening in Alberta, demonstrating the feasibility of decarbonization progress.

[14] Karambir Singh, Binnu Jeyakumar, "Budget 2023 shows federal commitment to clean electricity - what does that mean for the provinces?," *Pembina Institute*, April 28, 2023. https://www.pembina.org/blog/budget-2023-shows-federal-commitment-clean-electricity-what-does-mean-provinces.

2. Overview of Alberta’s grid decarbonization

Alberta has a unique, market-based electricity system designed to foster innovation adoption, adaptability and market responsiveness. It has proven remarkably adept at transitioning away from highly polluting sources toward lower-emitting sources when clear and reliable policy and market rules have been implemented to guide investment decisions and operating behaviour. Indeed, this progress has exceeded expectations, often at much lower cost than critics forecast.[15] Nevertheless, there is still a considerable distance to travel to reach a net-zero grid.

2.1 Alberta’s electricity system

Due to its reliance on fossil fuels — historically coal, and now natural gas — Alberta is responsible for a significant portion of Canada’s electricity emissions. In 2021, Alberta accounted for less than 10% of Canada’s electricity generation, but nearly half of all electricity emissions (Figure 3).

[15] Upon its announcement in 2015, Alberta’s 15-year coal power phase-out timeline was met with pushback surrounding feasibility. That timeline has since been cut in half. Source: Benjamin Thibault, Binnu Jeyakumar, Grace Brown and Kaitlin Olmsted, *From Coal to Clean: Canada’s progress toward phasing out coal power* (Pembina Institute, 2021), 5. https://www.pembina.org/pub/progress-coal-clean

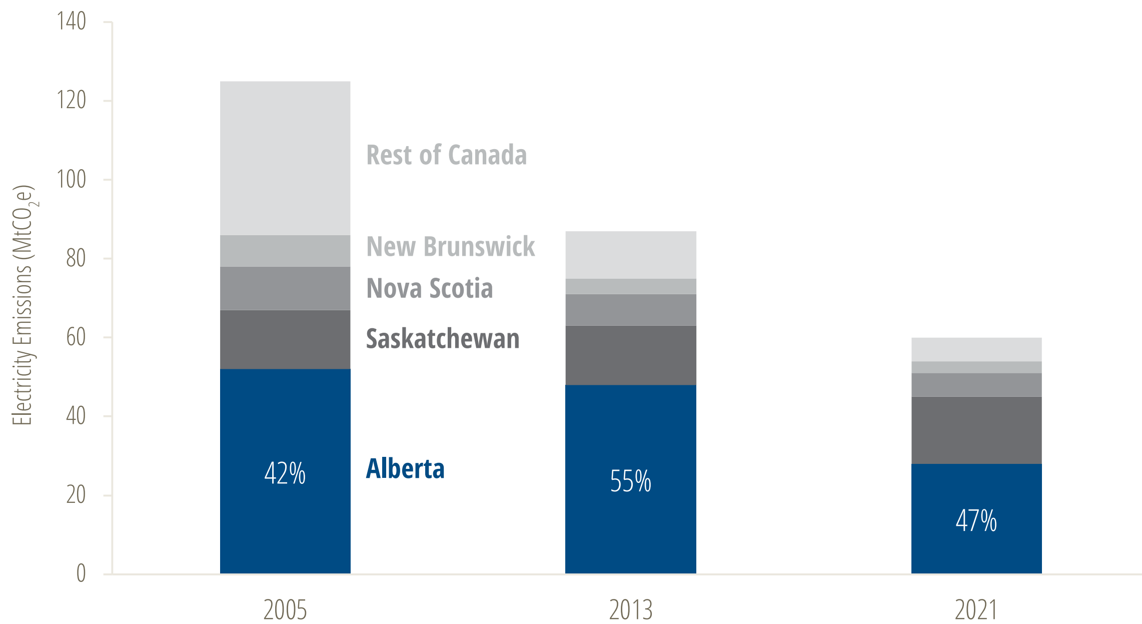

Figure 3. Canada's electricity emissions by region, 2005, 2013, and 2021

Data source: ECCC[16]

That said, Alberta has made notable progress in cleaning its electricity grid in the past 16 years. Since 2005, grid emissions intensity in the province has dropped from 908 to 510 gCO_2e/kWh. This is largely attributed to the province-wide phase-out of coal that is happening seven years ahead of schedule. Further emissions reductions are anticipated as the remaining 880 MW of dedicated coal-fired generation, and 516 MW of dual-fuel (coal plus natural gas) generation, is to be converted to 100% natural gas by the end of 2023.[17] For reference, coal-fired generation has an emissions intensity that is at least double that of natural gas. However, unabated natural gas remains a significant source of emissions and accounts for 49% of Alberta's electricity emissions profile as of 2021. This number increases if natural gas cogeneration is included.

While no two provinces have identical electricity systems, the following factors combine to create specific opportunities and challenges for transforming Alberta's grid to net-zero emissions:

- Deregulated market – Alberta's electricity market is more deregulated than that of any other Canadian province. This means that with the right market signals and policy incentives, independent, competing power producers can act quickly

[16] Emissions data does not include electricity from behind-the-fence generation at industrial facilities. Environment and Climate Change Canada, *Canada's Official Greenhouse Gas Inventory (*2023), Table A13-1, A13-4, A13-5, A13-9, A13-10. https://data-donnees.ec.gc.ca/data/substances/monitor/canada-s-official-greenhouse-gas-inventory/

[17] Capital Power, "Genesee Generating Station." https://www.capitalpower.com/about-genesee/

and take different innovative pathways to meet clearly signalled public goals. For example, the largest coal-operating companies in Alberta are taking different approaches to transitioning away from highly emitting generation, including large investments in renewables and battery storage; blending hydrogen in gas power plants; and carbon capture and utilization.[18]

- Decentralized planning – The presence of these independent power producers means Alberta's grid operator and policy planners are not able to control the location or nature of new generation additions, making cost-effective, long-term, sustainable system planning in the long-term public interest more challenging and risking higher overall system costs due to inaccurate forecasting.
- Significant cogeneration:
  - Alberta has significant cogeneration linked to other sectors, especially the oilsands sector, creating greater complexity in delineating sectoral net-zero requirements. As noted above, nearly two-fifths of electricity generated is from natural gas cogeneration facilities for oilsands production processes. These facilities must also decarbonize. However, given that their operations are driven by oilsands production rather than the dynamics of the electricity sector, their decarbonization should also be driven primarily by the emissions reductions pathways outlined for oilsands.
  - At the same time, while the majority of that cogeneration is produced and consumed "behind-the-fence," the balance is exported to the grid. This grid-exported electricity is exchanged through the power pool where it competes with most of the rest of Alberta's generators which are subject to the net-zero grid. While the driver and method will differ, Alberta's cogeneration facilities will need to decarbonize on both sides of the fence to credibly align with net-zero commitment.
- Lack of significant interconnection capacity – Alberta has a relatively small and isolated electricity grid, making large-scale low-emitting new supply (like reservoir hydro, conventional nuclear, and combined-cycle natural gas with carbon capture) a riskier bet for investors.
- Forecasting generator cost recovery – Recovering generator costs — capital costs in particular — from consumers is more difficult to model and forecast in Alberta because it is less straightforward. Many jurisdictions operate their electricity systems as cost-of-service. Under this model, the cost of operating and

[18] Grace Brown, Kaitlin Olmsted, Binnu Jeyakumar, *Progress from Coal to Clean: Comparing Canadian electric utilities' approaches to energy transition* (Pembina Institute, 2021).

maintaining the electricity system, including generator capital costs, are recovered through consumer utility bills. Alberta's electricity market is deregulated and competitive, meaning consumer costs could actually be higher or lower than total electricity system costs. This balance is dynamic and depends on a number of factors, such as market behaviour, competitiveness, and generation supply mix.

2.2 Grid decarbonization progress in Alberta

The concept of pathways toward electricity grid decarbonization is not new to Alberta. The Pembina Institute published its first report, Greening the Grid, on the topic in 2009. At the time, Alberta was heavily reliant on coal-fired electricity which represented 74% of generation in the province.[19]

The report identified several opportunities for reducing greenhouse gas emissions from electricity generation to achieve a cleaner and more reliable grid within 20 years, namely:

- phasing out coal fired generation
- implementing energy efficiency measures
- building out more renewable capacity (wind, hydro, solar, biomass, geothermal)
- installing more micro-generation (wind, solar, cogeneration)
- investing in energy storage
- increasing adoption of industrial cogeneration
- developing carbon capture and storage as needed

The Pembina Institute published a followup report, Power to Change, in 2014, providing an overview of the major changes that had occurred in Alberta's electricity mix since 2009, and further developing scenarios through which the province could reduce its emissions.[20] Opportunities outlined in the 2014 report mirrored those from its predecessor, though with more ambitious coal phase-out and renewable procurement targets, along with an option for utilizing existing coal-fired power assets by co-firing

[19] Tim Weis and Jeff Bell, *Greening the Grid: Powering Alberta's Future with Renewable Energy* (Pembina Institute, 2009), 11, 23. https://www.pembina.org/pub/greening-grid

[20] Benjamin Thibault and James Glave, *Power to Change: How Alberta can green its grid and embrace clean energy* (Pembina Institute, 2014). https://www.pembina.org/pub/power-change

with biomass.[21] Results of both the 2009 and 2014 studies showed the potential for significant electricity sector emissions reductions before the end of the decade (Figure 4).

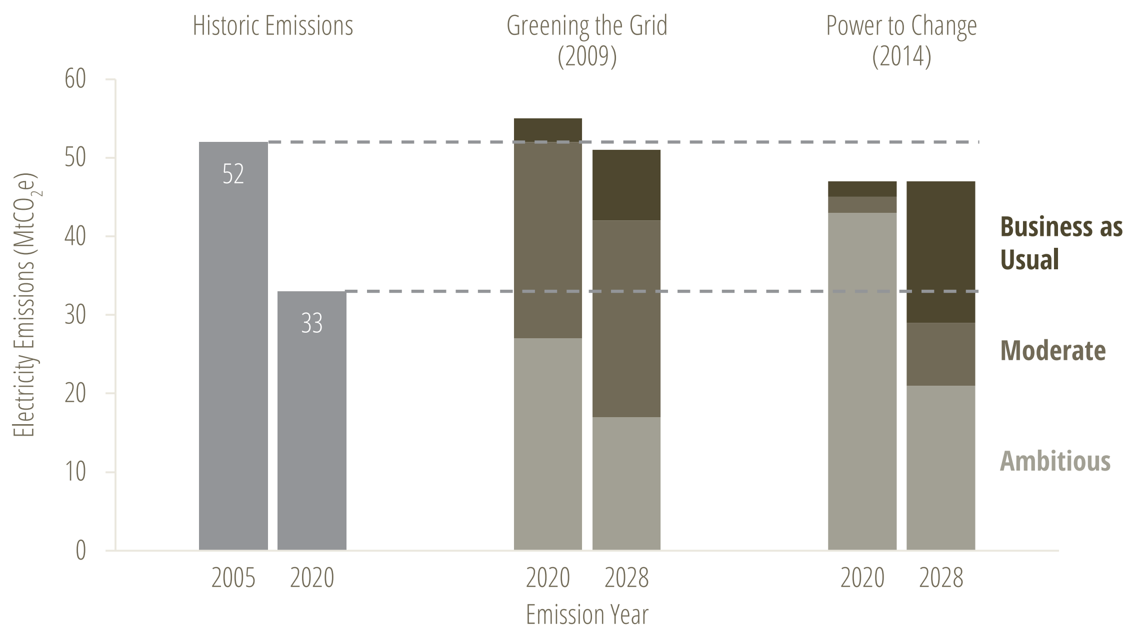

Figure 4. Comparison of Alberta electricity decarbonization scenarios of previous Pembina Institute reports

Data source: ECCC[22]; Pembina Institute[23]

At the time of publication of both reports, critics questioned the feasibility of the decarbonization pathways proposed. However, as it turns out, Alberta's grid decarbonization has progressed much more quickly than anyone — even the Pembina Institute — foresaw or suggested, as shown by the 2020 actual emissions in Figure 4. This is because many of the biggest measures suggested in the report proceeded more quickly and thoroughly than anyone imagined at the time, in particular the phase-out of coal-fired power and the growth of renewable energy.

Even in 2014, Power to Change only foresaw a gradual phase-out of older coal plants by 2031, while converting younger units to co-fire coal with biomass into the 2030s and

[21] Biomass refers to recently living organic matter such as wood, agriculture waste products, or municipal organic waste. For use in electricity generation, biomass is typically converted to a more convenient form, such as wood pellets. Source: Pembina Institute, *Biomass Sustainability Analysis: Summary Report* (2011), 3. https://www.opg.com/document/biomass-sustainability-analysis-report-pdf/

[22] Emissions data does not include electricity from behind-the-fence generation at industrial facilities. *Greenhouse Gas Inventory,* Table A13-10.

[23] *Greening the Grid,* 70; *Power to Change,* 17.

beyond. Instead, a combination of more effective carbon pricing and both provincial and federal coal phase-out commitments, all announced in 2015 and 2016,[24] began to push coal plant utilization down beginning in 2018. Over the ensuing half-decade, coal plant owners began announcing and then implementing coal plant retirements and conversions to natural gas. This has resulted in coal combustion for electricity generation ceasing completely this year (2023), many years ahead of the regulatory schedule and the Pembina Institute's most ambitious scenarios (Figure 5).

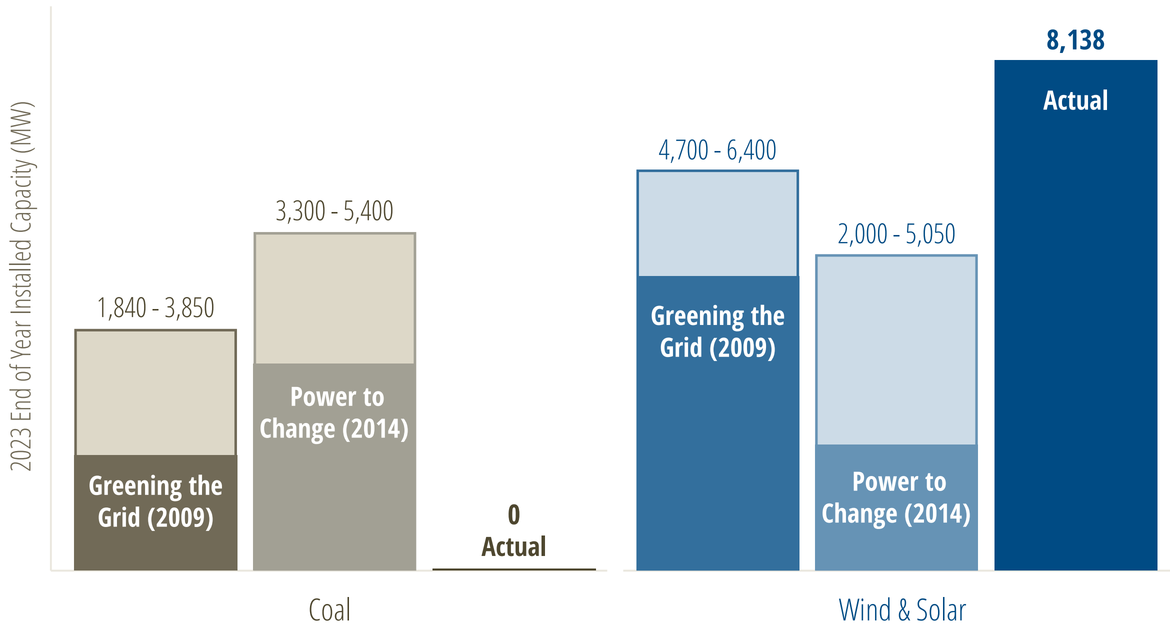

Figure 5. Installed capacity projections of coal-fired generation and renewables in previous Pembina Institute reports, compared to actual 2023

Data source: ECCC[25]; Pembina Institute[26]

Meanwhile, investment in new renewable electricity generation has also dramatically outpaced even the most ambitious forecasts, also shown in Figure 5. Power to Change's most ambitious scenario foresaw Alberta installing 5,000 MW of wind capacity by 2023 and around 50 MW of solar. By the end of this year, wind projects currently under construction will bring the installed wind capacity to around the 5,000 MW mark, while higher capacity factors mean that wind energy will outpace the projected energy production by a serious margin. Solar, meanwhile, will likely surpass 3,000 MW.

[24] *From Coal to Clean*, 27-28.

[25] Emissions data does not include electricity from behind-the-fence generation at industrial facilities. *Greenhouse Gas Inventory,* Table A13-10.

[26] *Greening the Grid,* 70; *Power to Change,* 17.

Under-predicting investment in renewable energy is not limited to the Pembina Institute (Table 1). In the most ambitious scenario of their 2021 Long-term Outlook, the Alberta Electric System Operator (AESO) showed Alberta's wind and solar fleets only reaching 3,500 MW and 1,100 MW by 2023 respectively.[27] Similarly, the *Renewables and Storage Rush* scenario from their Net-Zero Emissions Pathways report predicts 3,800 MW of wind and 1,800 MW of solar by the same year.[28] Meanwhile, in Canada's Energy Future 2021, under the Evolving Policies scenario, Canada Energy Regulator showed Alberta having 2,800 MW of wind and 640 MW solar.[29] As these numbers indicate, under-estimating investments in renewable energy and over-estimating the cost of grid transformation is fairly common; grid decarbonization scenarios would benefit from accounting for increasing desire to invest in renewable energy, especially in the private sector.

[27] Alberta Electric System Operator, *AESO 2021 Long-term Outlook* (2021). https://www.aeso.ca/assets/Tariff-2021-BR-Application/Appendix-K-AESO-2021-Long-term-Outlook.pdf

[28] Alberta Electric System Operator, *AESO Net-Zero Emissions Pathways Report* (2022). https://www.aeso.ca/assets/AESO-Net-Zero-Emissions-Pathways-Report-July7.pdf

[29] Canada Energy Regulator, *Canada's Energy Future 2021* (2021). https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2021/canada-energy-futures-2021.pdf

Table 1. Comparison of renewable energy forecasts for 2023

Scenario	Renewable Capacity			
	Wind (MW)	Below current	Solar (MW)	Below current
Current situation	**5,046** (by end of year; 3,618 as of May 2023)	--	**3,102** (by end of year; 1,209 as of May 2023)	--
Power to Change, *Clean Power Transformation* (May 2021, Pembina Institute)	5,000	**1%**	50	**96%**
Long-term Outlook, *Clean Technology* (June 2021, AESO)	3,500	**31%**	1,100	**65%**
Net-Zero Emissions Pathways, *Renewables and Storage Rush* (June 2022, AESO)	3,800	**25%**	1,800	**42%**
Canada's Energy Future, *Evolving Policies* (December 2021, Canada Energy Regulator)	2,800	**44%**	640	**79%**

After competitive government procurements landed very attractive long-term contract rates for wind and solar, long-term private-sector contracts for wind and solar have driven the nation-leading growth. According to the Business Renewable Centre-Canada, corporate and institutional procurement of renewable energy reached 2 GW in 2022, three years ahead of the expected timeline.[30] In 2022, renewables (wind, solar, and hydro) were responsible for 12% of all electricity generated in the province (Figure 6). This increases to 17% if you discount behind-the-fence generation at cogeneration facilities.[31] This proportion is also slated to grow considerably as the newly contracted renewable projects come online.

[30] Business Renewables Centre Canada, "Deal Tracker." https://businessrenewables.ca/deal-tracker

[31] Alberta Electric System Operator, *2022 Annual Market Statistics*. https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/

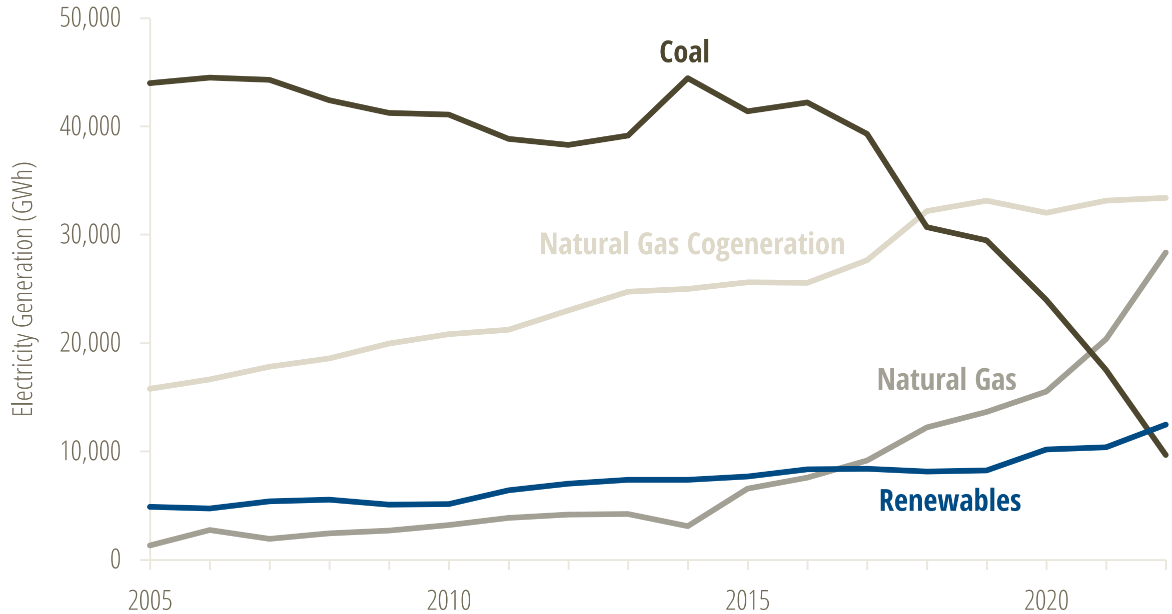

Figure 6. Alberta's electricity generation mix, including behind-the-fence, 2005–2022

Data source: AUC;[32] AESO[33]

The combined result has been for electricity sector emissions reductions beginning in 2018 that have impressively outpaced even the most ambitious emissions reduction scenario contemplated in the 2014 Power to Change, shown in Figure 4. In this way, past Pembina Institute emissions reduction scenarios — though described by some critics at the time as impractical or too costly — proved to be overly cautious once effective policies were instituted to prompt emissions reduction investments and innovations. This shows how market dynamics can be leveraged to effectively reduce emissions in this sector.

2.3 Looking forward — the trajectory of Alberta's grid

There remains a lot to be done to reach the 2035 net-zero grid goal and, in the near term, to avoid locking Alberta into new capital investment that is incompatible with net-zero. As the last coal plants near retirement, Alberta continues to greenlight new fossil-fuel generation. As of June 2023, there is 1,791 MW of new unabated natural gas capacity under construction, 416 MW of unabated natural gas capacity with regulatory

[32] Alberta Utilities Commission, "Annual electricity data: Total generation," 2022. https://www.auc.ab.ca/annual-electricity-data/

[33] *2022 Annual Market Statistics.*

approval, and 1,394 MW of upcoming coal-to-gas conversions with future abatement plans, all with an expected in-service date prior to 2025.[34]

Investment in unabated natural gas capacity poses several risks to Albertans: exposing them to the inherent price volatility of natural gas, a global commodity; and potentially leaving them to foot the bill if those assets become stranded.[35] As uncompetitive gas capacity is “pushed” out of the market, Albertans will continue paying for the unused transmission infrastructure and any compensations that the generators may seek for their stranded assets.

Under the proposed framework of the Clean Electricity Regulations, gas plants commissioned prior to December 31, 2024, would be subject to less stringent emissions standards than those commissioned in or after 2025. This flexibility, intended to allow older gas plants to avoid premature shutdown due to new government policy, has inadvertently sent a signal for investment into new unabated gas assets between now and 2025. Recent analysis by the Pembina Institute has shown that, depending on the EoPL defined in the CER, between 6 and 10 GW of unabated gas may be exempt from physical emission standards in 2035, potentially resulting in up to 22 $MtCO_2e$ of annual GHG emissions — well above the International Panel on Climate Change (IPCC) target for only “residual” emissions to remain.[36] For reference, in their median 1.5 degree-aligned scenario, IPCC targeted an allowance of 3% unabated natural gas electricity generation by 2035.[37]

Further action is necessary to ensure the right investment signals are sent to achieve the net-zero outcome. Those measures may involve regulatory requirements or market policies, initiatives and supports to enable the deployment of key technologies, and infrastructure investments that will achieve the best net-zero outcome. The certainty these measures will provide will further foster reliability and affordability on our grid.

[34] Alberta Electric System Operator, *Long Term Adequacy Report: February 2023* (2023), 5-9. https://www.aeso.ca/market/market-and-system-reporting/long-term-adequacy-metrics/

[35] An asset becomes stranded when it is no longer able to make a return on investment. Natural gas assets can become stranded through economic (rising fuel costs or unfavorable market dynamics) or regulatory factors (policy intervention limiting their operation). Source: Katie Auth, Jacob Kincer and Mark Thurber, *Untangling ‘Stranded Assets’ and ‘Carbon Lock-in’* (Energy for Growth Hub, 2022). https://www.energyforgrowth.org/memo/untangling-stranded-assets-and-carbon-lock-in/

[36] Nick Schumacher, Karambir Singh, Binnu Jeyakumar, and Will Noel, *The Risk Natural Gas Plants Pose to a Clean and Affordable Electricity System: An analysis of Growing Natural Gas-fired Electricity Generation in Alberta and Saskatchewan* (Pembina Institute, in preparation).

[37] Dave Jones, “Why Clean Power 2035 means No Coal by 2030,” *Ember,* June 23, 2022. https://ember-climate.org/insights/commentary/why-clean-power-2035-means-no-coal-by-2030/

This report explores the types of technology and infrastructure mixes that can help to achieve this outcome and to inform the additional measures necessary to foster the most efficient and reliable route to a 2035 net-zero grid.

3. Methodology

Alberta’s wholesale electricity market, facilitated by the Alberta Electric System Operator, is deregulated and competitive. Every hour, the wholesale price[38] of power (known as the “pool price”) is set by the marginal generator, as determined by an economic merit order.[39] In Alberta’s energy-only market, generators mainly earn revenue only for electricity that they export to the grid. Additional revenue can also be earned for providing ancillary services through separate markets, but the total value in these markets is very small compared to the energy market.

Energy market modelling was performed by Dr. Tim Weis and Jessica Van Os of the University of Alberta using the energy modelling software Aurora from Energy Exemplar. The model includes representations of each power plant’s operations in Alberta, uses input demand forecast, technology-specific capital costs, natural gas prices and carbon constraints. Aurora forecasts price and dispatch to determine economically viable fleets to meet hourly demand over the forecast timeframe. The model is not a prediction of the viability of any specific future project, as individual plant’s build decisions are unique. Rather, **the objective of the model is to achieve the lowest overall system costs**.

3.1 Scenarios

For this work, scenarios were considered out to 2035, including annual capacity expansion and retirements, hourly dispatch, prices and emissions. Simulations cover six potential scenarios through which the province can achieve varying levels of emissions reductions (summarized in Table 2). Scenario names are based on a key characteristic or assumption applied during modelling.

[38] Not to be confused with the energy price that consumers pay. Retailers purchase electricity at hourly wholesale prices as determined by the deregulated market. Consumers then purchase electricity from their retailer at a price that may vary monthly or be fixed for up to 10 years, as determined by their chosen electricity plan.

[39] In a competitive electricity market, generators offer their power at the minimum price at which they are willing to operate. An economic merit order stacks generator offers in ascending order of offer price, with the price of power (i.e. the pool price) being set at the intersection of supply and demand. The generator that supplies the final MWh of electricity to meet demand is known as the marginal generator.

Table 2. Scenario comparison

Scenario	Measures implemented under scenario			
	TIER high-performance benchmark	Intertie capacity with B.C. and Montana**	Storage capacity	CO_2 emissions
High Credit (status quo)	-1% annually*			
Baseline	approaches 0 linearly by 2035*			
Increased Trade	approaches 0 linearly by 2035*	+1,100 MW in 2030		
High Storage	approaches 0 linearly by 2035*		+1,100 MW by 2030	
Near-Zero Emissions	approaches 0 linearly by 2035*			near-zero by 2035***
Near-Zero Emissions+	approaches 0 linearly by 2035*	+2,200 MW in 2030	equal to at least 25% of new wind and solar capacity	near-zero by 2035***

*starting at 0.37 tCO_2e/MWh in 2022

**currently 1,100 MW

***excluding residual carbon capture emissions, biomass, and behind-the-fence cogeneration

The *High Credit* scenario provides insight into what may happen under the status quo, with no alterations made to the electricity policy framework as of March 2023. This scenario examines the behaviour of the Alberta electricity market as the price of emissions increases with the carbon price while the electricity high-performance benchmark (HPB) defined under the provincial Technology Innovation and Emissions Reduction (TIER) regulation tightens every year by 1%.[40]

[40] Alberta's TIER regulation defines and implements the provincial industrial carbon pricing and emissions trading system. It incentivizes industrial facilities to reduce emissions through compliance costs and credits, determined by a facility's emissions performance relative to a benchmark. High-performance benchmarks are set to the most emissions-efficient facilities and may change over time. Government of Alberta, *Technology Innovation and Emissions Reduction Regulation*. https://www.alberta.ca/technology-innovation-and-emissions-reduction-regulation.aspx

There are diminishing incremental emissions that are displaced as an electricity grid decarbonizes. By the time a net-zero grid is achieved, any incremental renewable energy supply is no longer displacing a counterfactual emitting generation source. As such the emissions benchmark for electricity should decrease to zero. This is illustrated in our *Baseline* scenario, which builds off the *High Credit* scenario and shows the impact of increasing the tightening rate on the electricity HPB such that it reaches 0 tCO_2e/MWh by 2035. This would expose emitting plants to the full carbon price by 2035 while simultaneously eliminating the production of emissions performance credits by wind and solar. As the name suggests, all subsequent scenarios start from this *Baseline*.

Increased Trade doubles the import and export capacity with Alberta's neighbouring jurisdictions, British Columbia and Montana (referred to here as the BC/MT intertie), providing a destination for excess renewable generation and increasing Alberta's ability to access B.C.'s hydroelectric resources.

High Storage provides an alternative solution to increase grid flexibility using energy storage (batteries, compressed air, and pumped hydro) rather than intra-provincial transmission.

The near-zero emissions scenarios place a constraint on emissions, such that the market achieves near-zero emissions by 2035. Two potential pathways are explored under these scenarios: the *Near-Zero Emissions* scenario with no increased trade or storage capacity and the *Near-Zero Emissions+* scenario which both triples the capacity of the BC/MT intertie in 2030 and requires at least 25% of new wind and solar capacity to be accompanied by energy storage. Detailed model inputs and assumptions for all scenarios can be found in Appendix A.

3.2 Ensured reliability

The ultimate objective of Aurora is to achieve the lowest overall system cost over the study horizon. However, the model is also constrained by several other factors to ensure the results are realistic. One important example relates to grid reliability. Every hour, Aurora requires that demand is met, through a combination of internal supply, imports, and demand response, while simultaneously maintaining a user-defined operating reserve margin. In this way, **the model does not sacrifice reliability for the sake of affordability**.

3.3 Treatment of cogeneration assets

In Alberta, cogeneration plants provide utility outside the electricity market, generating both electricity and steam for the facilities to which they are linked (i.e. behind-the-fence) and selling excess electricity into the power pool (i.e. net-to-grid). The differentiation of behind-the-fence and net-to-grid electricity is demonstrated for Alberta's fleet of cogeneration facilities modelled over five days in Figure 7.

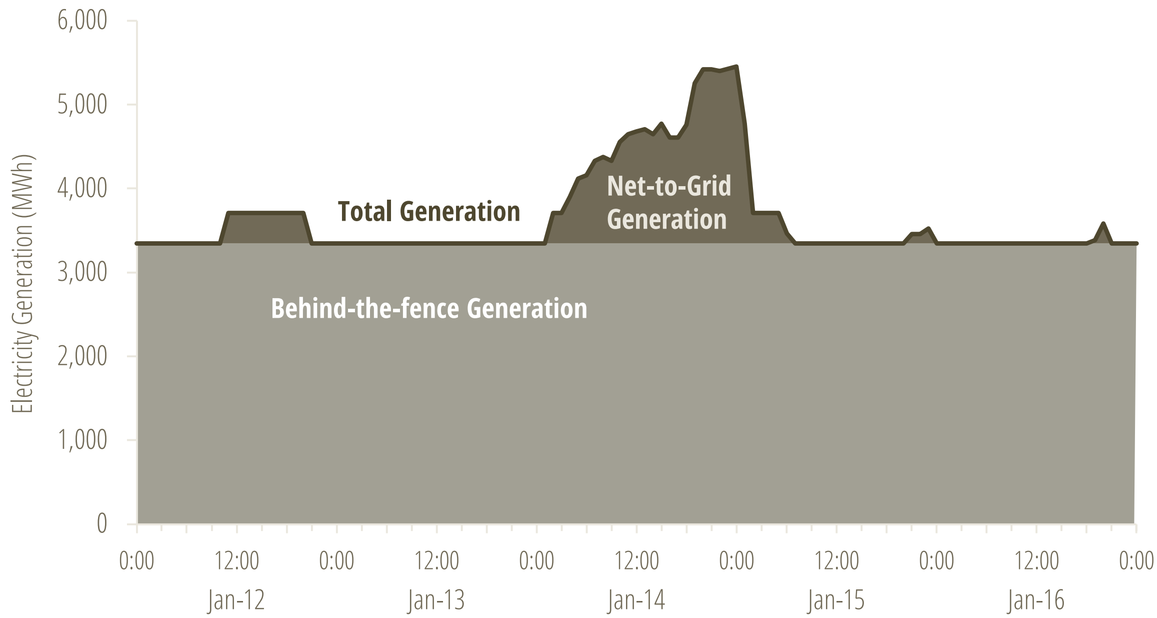

Figure 7. Differentiation between behind-the-fence generation and net-to-grid for natural gas cogeneration plants over five days

In 2022, behind-the-fence (BTF) loads at industrial facilities represented 58% of all cogeneration output and 29% of all electricity consumed in Alberta.[41] The overall economics of on-site generation at these facilities are driven by factors such as oil prices, minimum loads on oil production equipment, etc., and are not reliant solely on the same price signals as the rest of the electricity market and their lifespans. Due to the significant influence of these extrinsic factors on cogeneration behaviour, the resulting generation, emissions, and costs related to BTF activities are considered separately from those related to electricity exported to the grid. Emissions resulting from BTF steam generation are estimated and removed from our reporting.

In other words, **we assume that the emissions resulting from all cogeneration activities outside of the Alberta power pool** — including both BTF generation and

[41] *2022 Annual Market Statistics*, 8.

the industrial processes driven by steam — **will be offset or abated to align with emissions reductions commitments made outside the electricity sector**. That said, these facilities are still subject to carbon pricing, as well as other emissions regulations and commitments. The oilsands industry and government (both provincial and federal) have proposed net-zero emissions goals. Cogeneration facilities operating past 2035 could reduce their emissions via technologies such as carbon capture and storage, hydrogen, nuclear or other electrification to align with these goals, though alternative technology choices for cogeneration have been treated as out of scope of this report.

4. Results

Results of the electricity market modelling are presented below, separated into each of the six scenarios described in section 3. To provide a clear baseline, key results from AESO's 2021 Long-term Outlook (LTO) *Reference Case* are also provided. For the sake of brevity, detailed graphics are only provided for the *High Credit* scenario, with subsequent discussions focusing on key findings from the alterations being made. The next section provides a summary of our results, highlighting the key outcomes of our modelling and comparing various metrics across the scenarios.

4.1 AESO 2021 Long-term Outlook *Reference Case*

Every two years, the Alberta Electric System Operator publishes their Long-term Outlook report, detailing their forecast of Alberta's electricity demand and generation over the subsequent decades. The LTO helps guide transmission system planning, among other long-term generation and market assessments. To validate their assumptions, AESO holds public consultations with stakeholders through engagement sessions and by soliciting feedback to preliminary LTO results. Similar to the Pembina Institute's approach, the 2021 LTO includes four different scenarios to compare potential future market outcomes. Key outcomes from the 2021 Long-term Outlook *Reference Case* are outlined below.

AESO's LTO forecasts are driven by a plethora of assumptions, such as carbon policy, corporate power purchase agreements (PPAs), distributed energy resources, electric vehicle adoption and charging profiles, and improvements in energy storage technologies. As there was no legislated carbon price beyond 2022 at the time of writing the 2021 LTO, the LTO *Reference Case* assumes a \$50/tCO_2e carbon price in 2022, with subsequent annual increases based on inflation.[42] This assumption is now out of date, and using the 2021 LTO *Reference Case* (without updating it) as a baseline scenario in their Net-Zero Emissions Pathways report has resulted in an overestimation of the incremental cost of reaching net-zero.

[42] The *Clean-Tech* scenario from the 2021 LTO did include the now-legislated carbon pricing schedule, increasing from \$50/tCO_2e in 2022 to \$170/tCO_2e in 2030 in increments of \$15 per year. *AESO 2021 Long-Term Outlook*, 7.

AESO's LTO generation forecasts start with the addition of projects that are currently under construction or undergoing regulatory review, as well as those whose economics are influenced by factors outside of the electricity sector. New cogeneration capacity is added based on trends from the oil and gas sector. Similarly, non-merchant wind and solar projects (i.e. projects that sell their power outside the wholesale market — part of the ongoing boom in corporate PPAs) are also included. All other generation additions are driven by increasing electricity demand, retirements of existing units, decreasing capital costs for renewables and storage, and increasing fuel prices. During their iterative process, AESO considers various combinations of new combined-cycle gas, simple-cycle gas, wind, and solar projects. Additions are made based on future market behaviour and expected economic returns. The 2021 LTO does not consider the expansion of the BC/MT intertie.

The 2021 LTO *Reference Case* shows a continued reliance on fossil fuel generation, though with a shift from coal to natural gas. Between 2021 and 2041, their modelling shows 75% to 82% of annual generation coming from natural gas-fired technologies, mostly cogeneration. During those two decades, the LTO *Reference Case* includes the addition of 1,580 MW of wind and 300 MW solar, though most of this new capacity was added outside of the wholesale market and this prediction has already been outstripped by current installed capacities (Table 1). The forecasted generation mix achieves modest emissions reductions, with 17.7 $MtCO_2e$ of electricity emission in 2035, not including behind-the-fence cogeneration.

4.2 *High Credit* (status quo)

Our *High Credit* scenario shows the projected outcomes under policies in place as of March 1, 2023, most notably the federal carbon price schedule and the TIER HPB. Under this carbon policy structure, the cost of emissions for electricity generation will grow with the carbon price as it increases by $15 per year from $65 in 2023 to $170/$tCO_2e$ in 2030. At the same time, the tightening of the HPB by 1%[43] per year will expose a larger portion of unabated generation to the rising carbon price, while slowly decreasing the volume of emissions credits generated by wind, solar and other non-emitting technologies. The synergy between these policy levers, balanced with the declining cost

[43] The tightening rate for electricity increased to 2% per year after modelling was complete. Source: Alberta Environment and Parks, *Compliance Year 2022 Large Emitter / Opt-in Compliance Workshop* (2023), 67. https://www.alberta.ca/assets/documents/epa-tier-lfe-compliance-workshop-2022-presentation.pdf

of wind and solar generation, shows potential for significant growth in renewable energy in the coming years (Figure 8).

Renewables

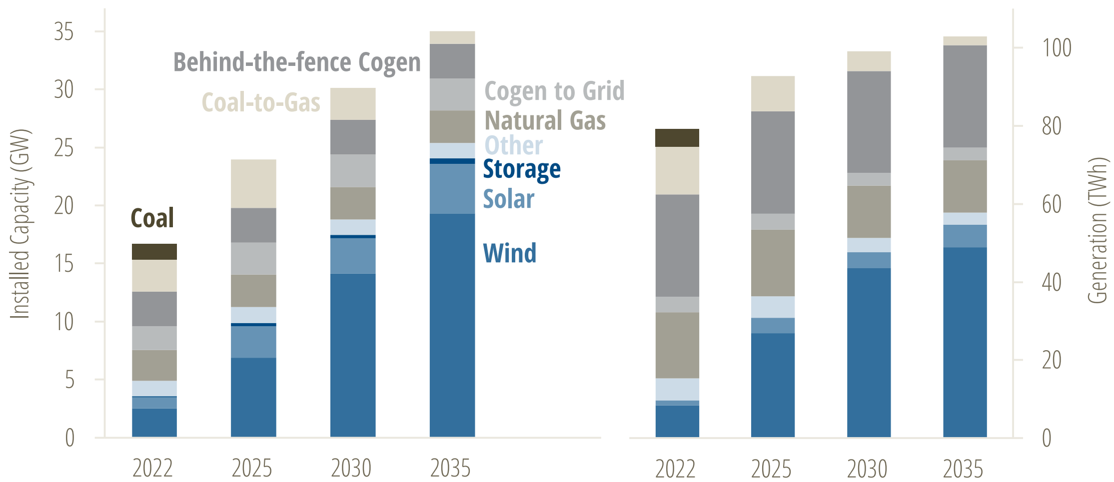

Figure 8. Installed capacity and total generation by fuel type, *High Credit* scenario, 2022–2035

In the *High Credit* (status quo policy) scenario, renewable energy is poised to continue its rapid growth over the coming decade, with wind capacity increasing by nearly eight times, with an average expansion of 1.3 GW per year.[44] More than half of all new wind capacity would be operational before 2027, with subsequent years showing modest growth, in part due to the decreasing emissions credit. Similarly, by 2035, solar capacity would increase by a factor of four, battery storage by a factor of seven and, excluding cogeneration assets, natural gas capacity would decrease by 30%, with most retirements being coal-to-gas retrofits (as required by federal regulations on greenhouse gas emissions from gas-fired power generation).

As more wind and solar capacity comes online it displaces fossil fuel generation, starting with higher-cost simple-cycle and coal-to-gas units, then eventually combined-cycle and grid-exported cogeneration. By 2025, both simple-cycle and coal-to-gas fleets' annual capacity factors would drop below 35%, while combined-cycle assets decrease from 80% to fluctuating between 50% and 60%. The early boom in wind

[44] In 2022, Alberta's wind capacity grew by 605 MW and solar by 745 MW. As of May 25, 2023, 1,600 MW of wind capacity and 1,288 MW of solar capacity are in the "execution" phase of connecting to the grid in 2023/2024. This suggests that 1.3 GW of new capacity per year is optimistic, but within the realm of possibility. Data source: Alberta Electric System Operator, "Connection Project Reporting," (accessed May 2023) https://www.aeso.ca/grid/transmission-projects/connection-project-reporting/

capacity increases the volume of low-priced hour exports to neighboring jurisdictions. Once this intertie export capacity has been completely filled, wind generation would be reduced (or "curtailed"). In other words, the modelling suggests that current policies favour building more wind capacity than the province can use, because wind can still generate carbon credits to offset lowered market prices. Under this scenario, renewable penetration (i.e., the contribution of renewables in meeting annual internal demand) reaches 55% of total electricity demand and 74% of the market when behind-the-fence (BTF) generation is excluded (Figure 9).

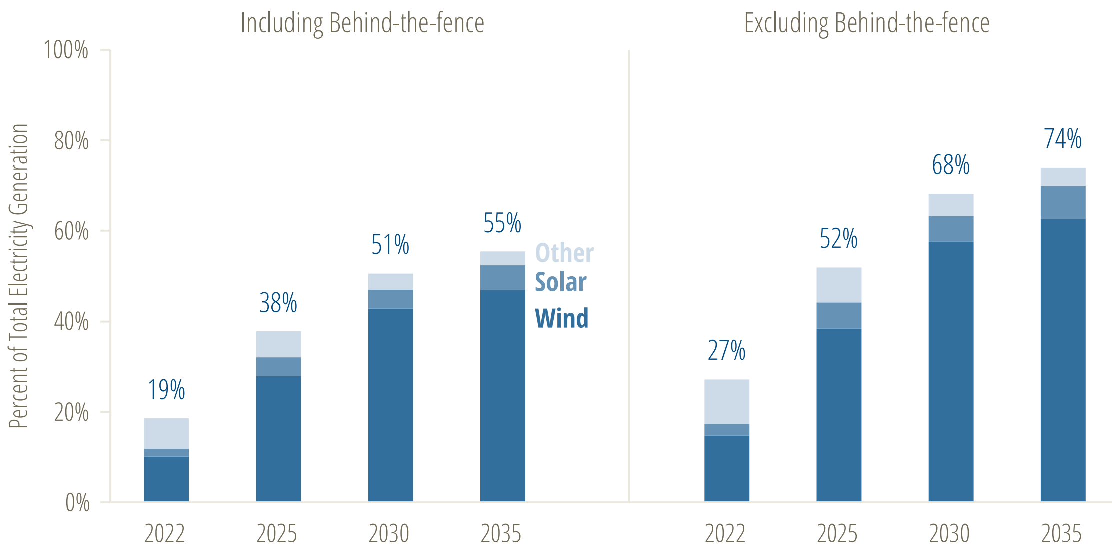

Figure 9. Renewables contribution to total electricity generation, *High Credit* scenario, 2022–2035

Emissions

With increasing renewable penetration comes a decline in GHG emissions. Relative to 2022, *High Credit* would result in a 41% reduction in total emissions and a 62% reduction in grid-export emissions by 2035 (Figure 10). All else held equal, this would drive a 33% decrease in Canada's current electricity emissions. However, in 2035 there are still 15 $MtCO_2e$ of residual emissions, 53% (8 Mt) of which are attributed to behind-the-fence activities. These results show that carbon pricing alone is not enough to get Alberta's electricity sector to net-zero. To meet the federal target of net-zero by 2035, more stringent policies are needed to eliminate or offset/negate the remaining 7 $MtCO_2e$ of non-BTF emissions.

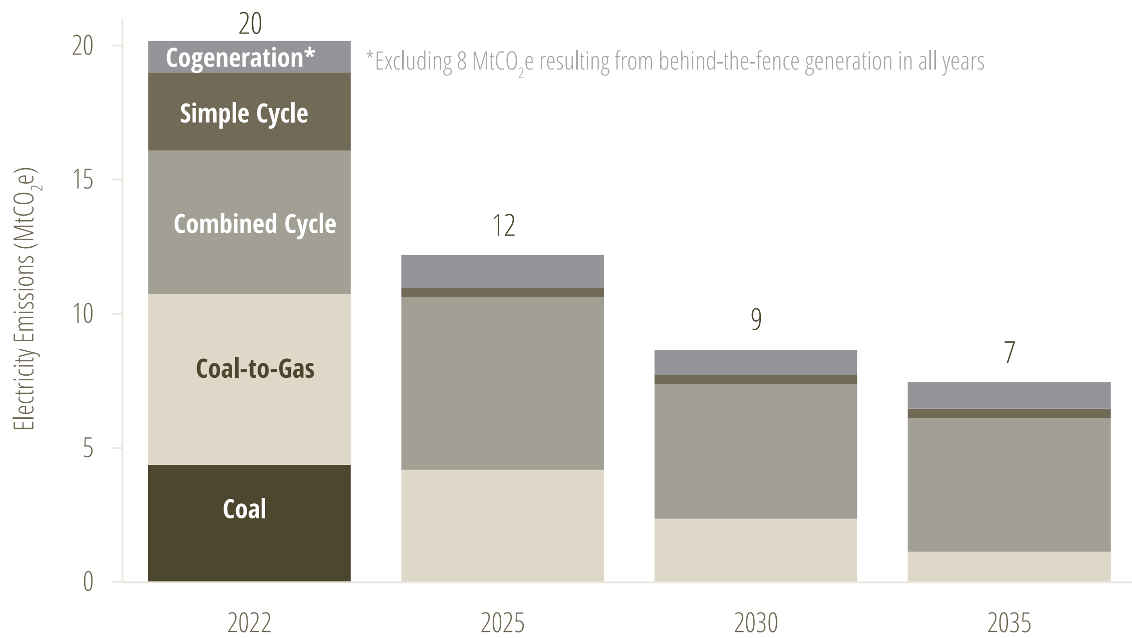

Figure 10. Annual electricity emissions by plant type, *High Credit* scenario, 2022–2035

High Credit results in lower 2035 emissions than all previous AESO analyses, with 9 Mt less than the LTO *Reference Case* and 0.1–1.4 Mt less than the Net-Zero Emissions Pathways scenarios. For these comparisons, electricity emissions from all industrial cogeneration facilities have been estimated and added back into AESO's reporting, which originally only include facilities that are "primarily engaged in the generation of bulk electric power" (see section B.1 in the Appendix for more details).

Due to the early boom in wind development, over half of all emissions reductions occur before 2025, with non-BTF emissions falling by 38%. This rapid decline in emissions, paired with a modest increase in total demand, brings Alberta's emission intensity down to 183 gCO_2e/kWh by 2025 and below the current national average (Figure 11) by 2035.[45]

[45] Canada's consumption intensity for 2021 was reported as 110 gCO_2e/kWh. Source: *Greenhouse Gas Inventory,* Table A13-1.

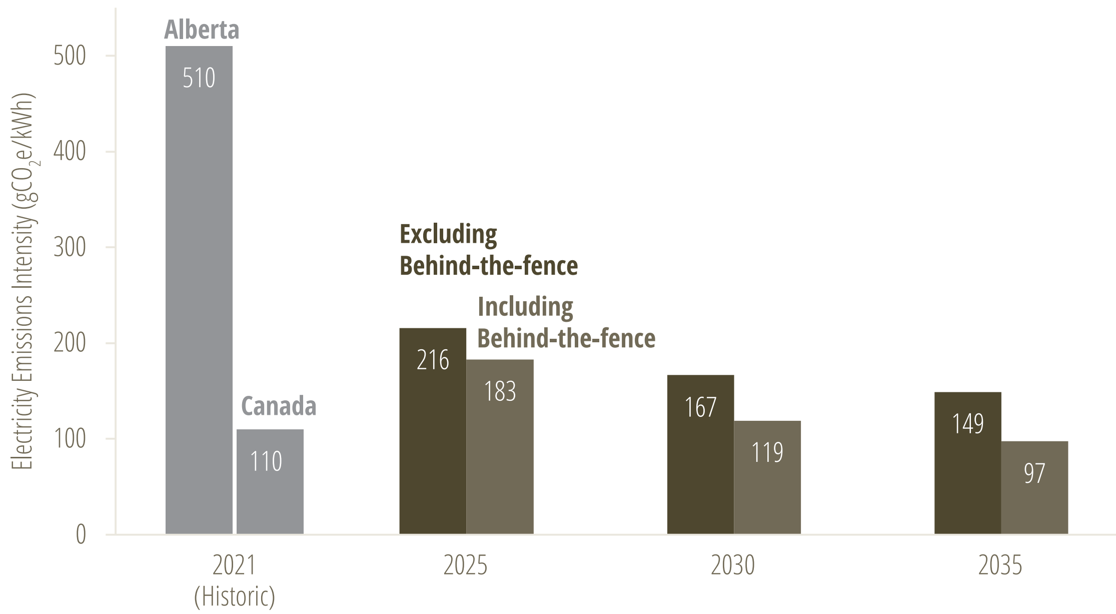

Figure 11. Electricity emissions intensity relative to historic values, *High Credit* scenario, 2021–2035

Data source: ECCC[46]

Cost

Regardless of the path forward, expanding and operating the electricity grid comes with a cost. As their name suggests, variable costs (fuel, emissions (due to carbon pricing), and variable operating and maintenance (O&M)) fluctuate with generator output. Similarly, fixed costs (capital, financing, and fixed O&M) are incurred regardless of whether a generator is producing power. Typically, renewable energy resources such as wind and solar have higher capital costs, lower O&M costs, and no fuel or emissions costs (in fact they can generate emissions revenues). On the other hand, fossil fuel plants have lower capital costs, but are more expensive to operate, especially as the price of fuel and emissions rise over time.

As the generating fleet transitions from primarily natural gas to a mix of gas, wind, and solar, there is a noticeable shift in cost allocation from fuel to capital costs. Prior to 2025, fossil fuel plants account for more than three-quarters of total system costs, most of which is from purchasing fuel. By 2035, renewables — wind, solar, hydro, and biomass — and battery energy storage account for 50–65% of system costs, but 55–73% of generation (Figure 9).

[46] Historic emissions data does not include electricity from behind-the-fence generation at industrial facilities. Data source: Source: *Greenhouse Gas Inventory,* Table A13-10.

Figure 12 shows total electricity system costs, excluding upgrades to the distribution network, out to 2035. Including operating costs for behind-the-fence generation and accounting for emissions revenues generated by wind and solar, total electricity system costs in 2035 for the *High Credit* scenario are estimated to be 7% lower ($6.538 billion less) than AESO's 2021 LTO *Reference Case*. However, simplified calculations suggest that with updated cost inputs (e.g., natural gas prices and carbon pricing policy), this difference may be up to 32% (see Figure 12 for more details). Similarly, *High Credit* total system costs are between 32% and 35% lower than AESO's Net-Zero Emissions Pathways scenarios as published.

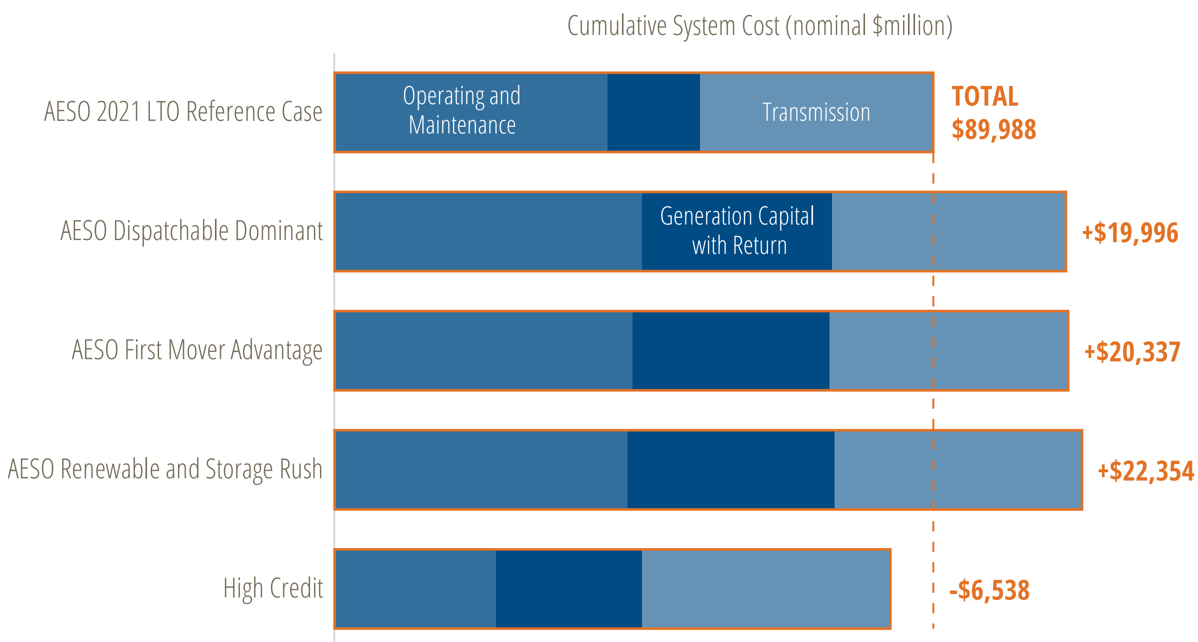

Figure 12. Electricity system costs, excluding upgrades to distribution, *High Credit* scenario, 2022–2035

Data source: AESO[47]

In Alberta's deregulated electricity market, retailers buy electricity from generators at wholesale costs. Consumers purchase electricity from the retailer of their choice at a price determined by their chosen electricity plan. Residential electricity prices consist of variable (¢/kWh) and fixed ($/day) components. These charges cover the cost of energy that is consumed, but also the operation and maintenance of the grid, taxes, municipal land access, administration fees, and other adjustments known as rate riders. According

[47] To account for transmission upgrades, operation, and maintenance, an annual increase to total costs, equal to AESO's *Renewables and Storage Rush* scenario, has been added to our scenarios. *AESO Net-Zero Emissions Pathways Report*.

to the Alberta Utility Commission (AUC), energy and delivery (i.e., transmission and distribution) charges account for up to 75% of a typical residential electricity bill.[48]

Using the wholesale pool price (plus a correction factor)[49] as an indicative measure of consumer energy charges, we can make a reasonable estimate of consumer electricity cost trends out to 2035. Relative to 2022, residential electricity prices are shown to decrease significantly by 2025 (Figure 13). This sudden decline in price is driven by the significant increase in wind generation which has no fuel cost and depresses the average pool price. By 2035, prices begin to increase, but remain 21% below 2022 values. Further details on this estimation can be found in section B.2 in the Appendix.

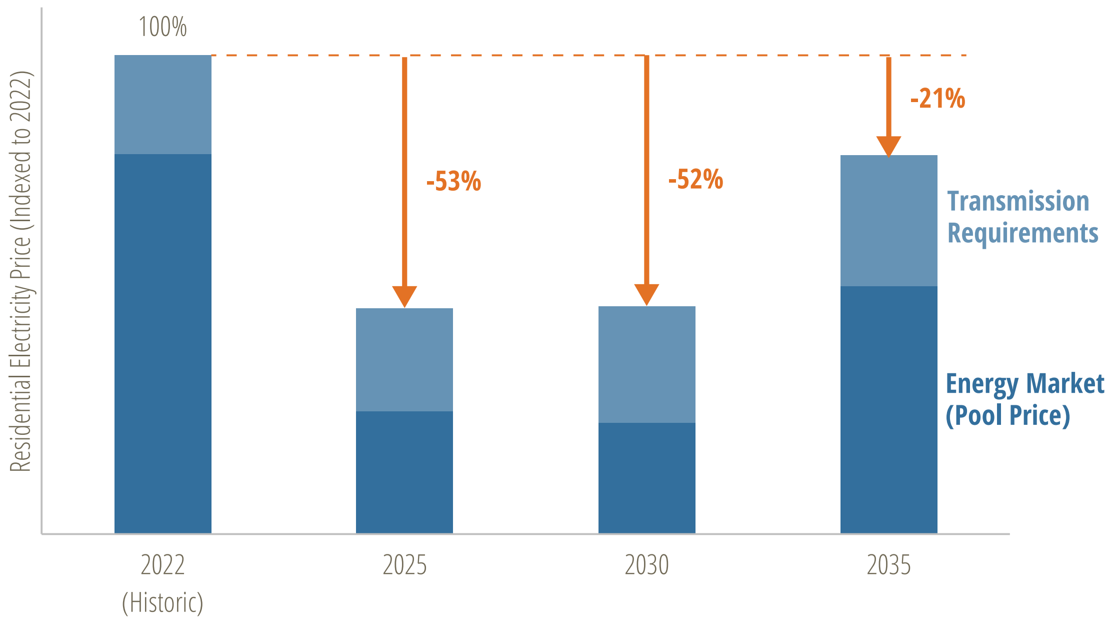

Figure 13. Change in residential electricity prices relative to 2022, excluding distribution charges and rate riders, *High Credit* scenario

Data source: Utility Consumer Advocate[50]

[48] Alberta Utility Commission, "Electricity Rates." https://www.auc.ab.ca/current-electricity-rates-and-terms-and-conditions/

[49] To account for instances in the model where generators are unable to recover their operating costs in the energy market using historic bidding patterns, we apply a correction factor to estimate the impact on the pool price if those generators had recovered their costs (plus an expected return on capital) through some other mechanism.

[50] For 2022: Direct Energy Regulated Rate Option and EPCOR transmission charges from Utility Consumer Advocate, "Rate Information." https://ucahelps.alberta.ca/rates.aspx

4.3 *Baseline* (TIER benchmark to zero)

Our *Baseline* scenario builds off *High Credit*, accelerating the reduction of the electricity HPB from 1% per year to 0.0285 tCO_2e/MWh per year such that it reaches zero by 2035. In doing so, the emissions from fossil fuel plants become fully priced as increasing amounts of their generation is subject to carbon pricing. Similarly, the revenue for wind and solar farms will increasingly depend on the wholesale cost of power as the ability to generate new emissions credits shrinks to zero.

Unsurprisingly, as the supply of emissions credits shrinks, the forecast for new wind and solar capacity is lower than our *High Credit* scenario. However, the decrease in installed renewable capacity does not result in a one-to-one decrease in renewable generation as curtailment of renewable energy is less of an issue for the smaller fleet. In fact, relative to *High Credit*, the 36% reduction in new wind capacity by 2035 results in only a 13% reduction in annual wind generation. Similarly, the reduction in curtailment also reduces the price discount that wind and solar would receive from the power pool.

On the other hand, as fossil fuel generators are subject to increasing levels of emissions pricing, natural gas generation decreases significantly. In 2035, excluding cogeneration assets, natural gas generation decreases by 27% relative to *High Credit*. This reduction in generation is offset by a small increase in grid-exported cogeneration and the addition of 1,480 MW of abated combined-cycle natural gas capacity. The resulting generation mix achieves similar annual emissions as *High Credit* by 2035. However, cumulative system costs are 21% higher, driven primarily by a 38% decrease in emissions revenues for wind and solar. Like *High Credit*, residential electricity costs are expected to decrease relative to 2022 values. The reduction in total cumulative emissions by only 1% suggests that carbon pricing alone is not a sufficient policy tool to achieve a net-zero grid.

4.4 Increased Trade

Increased Trade builds further on *Baseline*, exploring the impact of doubling the intertie capacity between Alberta, B.C. and Montana from 1,100 MW to 2,200 MW in 2030. An increase in trade between jurisdictions would be mutually beneficial, helping Alberta balance supply and demand with B.C.'s hydroelectric resources, and providing B.C. and Montana with low-cost wind power during times of excess supply in Alberta.

By doubling the intertie capacity, Alberta wind and solar installations increase relative to the *Baseline*, capitalizing on the increased export capability. In 2035, the *Increased Trade* wind fleet is 30% smaller than *High Credit* but generates 0.2% more electricity.

Similarly, solar capacity is 27% lower, but produces only 19% less electricity. This reduction in renewable curtailment leads to a renewable penetration level of 57% in 2035, 2% higher than the *Baseline* scenario with only 70% of the installed capacity.

With the improvements in renewable utilizations follows a decrease in demand for natural gas generation and new abated gas capacity. **By 2035, only 369 MW of abated combined-cycle capacity is added: more than 1 GW less than was required without the expanded intertie.** Excluding cogeneration, natural gas generation decreases by 31% relative to *High Credit*, with most of the reductions attributed to combined-cycle and coal-to-gas plants. The reduction in gas generation leads to a total emission reduction of 4% over the next 13 years and a 3% decrease in 2035 emissions. Our preliminary estimates show that, even when including the additional cost of expanding the intertie (details in section B.3 in the Appendix), cumulative system costs are only 2% higher than *Baseline*. Similarly, 2035 residential electricity prices are estimated to be only 5% higher with the additional intertie capacity.

4.5 *High Storage*

High Storage provides an alternative to increasing Alberta's intertie capacity with B.C. and Montana, using a mix of long and short duration energy storage technologies inside Alberta to improve the utilization of variable renewables. This scenario has the added benefit of mitigating reliability concerns associated with unexpected intertie interruption and the regulated limit to maximum capacity (most severe single contingency limit).[51]

Through reductions in curtailment, *High Storage* achieves high levels of renewable penetration, leading to decreased need for natural gas generation. However, due to duration limitations with currently available storage technologies, especially when compared to an increased intertie capacity, 1,480 MW of abated combined-cycle natural gas capacity is required to meet peak winter demands during low wind hours. As a result, emissions reductions for this scenario are marginally lower than those shown in

[51] The most severe single contingency (MSSC) limit relates to the grid's ability to handle a sudden loss of supply from a single source (generator or transmission). Currently, the MSSC in Alberta is 466 MW, meaning that any single supplier is unable to operate at a maximum rated capacity above that value. While doubling the intertie capacity between AB and BC/MT would run up against this limit, installing a fleet of distributed energy storage technologies would not, even if their combined capacity exceeds the MSSC. In fact, non-wires alternative such as energy storage have been suggested as one potential solution to increasing the MSSC. Source: Alberta Electric System Operator, *Summary of Stakeholder Feedback: MSSC options paper* (2023), 2-3. https://www.aesoengage.aeso.ca/evaluation-of-mssc.

Increased Trade. Total system costs are comparable to *Baseline*, with funds that were originally dedicated to wind fleet expansion being diverted into energy storage and abated natural gas. It is worth noting that, due to unfavourable pool price dynamics, our modelling suggests that most storage assets will be unable to turn a profit from energy arbitrage alone (that is, solely by purchasing power (charging) during low price hours and selling power (discharging) during high price hours). One potential solution is for the storage assets to be utility-owned, recovering their costs and sharing their surplus through rate riders or tariffs. Even so, ***High Storage*** **results in the lowest cost to ratepayers in 2035, with residential electricity prices estimated to be 24% below 2022 levels.**

4.6 *Near-Zero Emissions* and *Near-Zero Emissions+*

The above scenarios demonstrate various affordable paths toward a reliable low-emission grid, without explicitly defining an acceptable level of emissions to be considered net-zero. The Near-Zero Emissions scenarios provide insight into two potential solutions to eliminating any residual emissions, whereby the electricity market model is given strict conditions to meet emissions targets —excluding emissions from biomass, behind-the-fence cogeneration, and residual emissions from abated natural gas — by 2035. *Near-Zero Emissions+* includes the added benefit of tripling the BC/MT intertie to 3,300 MW in 2030 and installing 4 GW of storage capacity by 2035.

Without additional intertie and storage capacity, *Near-Zero Emissions* relies heavily on carbon capture and storage (CCS) to eliminate the residual emissions generated by unabated natural gas, requiring over 5,000 MW of abated natural gas capacity by 2035. The *Near-Zero Emissions+* scenario reduces the CCS requirement to less than half (1,800 MW).

Due to the uncertainty surrounding CCS costs, both capital and operating, we present our results with additional sensitivities to explore the potential impact of these projects going over budget. It is also worth noting that capital costs used in our analysis do not include the additional infrastructure required to store or transport the CO_2 after it has been captured. Further details on the sensitivity analysis can be found in section B.4 in the Appendix.

As the name suggests, these scenarios achieve near-zero emissions by 2035, with minimal residual emissions (<1 Mt) resulting from the CCS process. In *Near-Zero Emissions,* total system costs are within 1% of *Baseline*, though our sensitivity analysis shows that actual costs could be up to 3% higher than *Baseline* if CCS cost assumptions are adjusted.

Including the additional intertie and storage capacity in *Near-Zero Emissions+* results in only a 7–8% increase in cumulative system costs and a marginal decrease in 2035 emissions relative to *Near-Zero Emissions*. Residential electricity prices for both *Near-Zero Emissions* scenarios follow a similar pattern to *Baseline*. Only with a large build-out of CCS, energy storage, and intertie capacity do 2035 prices approach 2022 levels.

5. Discussion of key results

Rapid reduction of Alberta's electricity emissions has been driven by a combination of effective electricity policy and the declining cost of renewable energy. Since the announcement of the federal and provincial coal phase-outs in 2015–2016, Alberta generators are on track to retire or convert their remaining coal assets by the end of 2023, six years ahead of schedule. At the same time, its wind and solar fleets have expanded significantly, driven by a combination of declining capital costs and low-cost financing enabled by the proliferation of corporate virtual power purchase agreements. Alberta's current generation mix shows that the pace of the phase-out and clean energy development has exceeded even the more ambitious scenarios in the Pembina Institute's previous two analyses (in 2009 and 2014) of grid decarbonization in Alberta.

There are various paths through which continued decarbonization could be achieved. The scenarios outlined in section 4, though not exhaustive, provide valuable insight into the benefits and drawbacks of various electricity decarbonization strategies in Alberta. In this section, we discuss key results and compare various metrics between our modelled scenarios. Further details comparing the analysis of this report with the AESO 2021 Long-term Outlook and Net-Zero Emission Pathways reports are included in the Appendix under section B.1.

5.1 Economic benefits

The concern expressed publicly around system and consumer costs from emissions reduction scenarios, while understandable, are not borne out in our analysis — our scenarios are lower-cost than recent AESO analyses have predicted, including the 2021 LTO *Reference Case* and all three Net-Zero Emissions Pathways scenarios. We also predict that household electricity costs in the coming decade will be lower than the costs that consumers experienced in 2022. At the same time, we show that a decarbonized electricity grid would increase Alberta's energy export opportunity through sales of excess clean electricity through the BC/MT intertie.

Lower system costs

All scenarios have lower electricity system costs than AESO's 2021 LTO *Reference Case*, as shown in Figure 14. Cost reductions do not take into account federal government funding inputs that can reduce system costs further and the additional costs of addressing residual emissions through carbon removal activities. As is the case with the AESO's Net Zero Pathways analysis, these potential system cost savings would further decrease the system costs if constructive federal-provincial engagement enabled direct federal contribution to the net-zero trajectory. Updated natural gas costs and carbon pricing policy closes the gap in total system costs between their baseline (2021 Long-term Outlook *Reference Case*) and decarbonization (Net-Zero Emissions Pathways) scenarios, also shown in Figure 14.

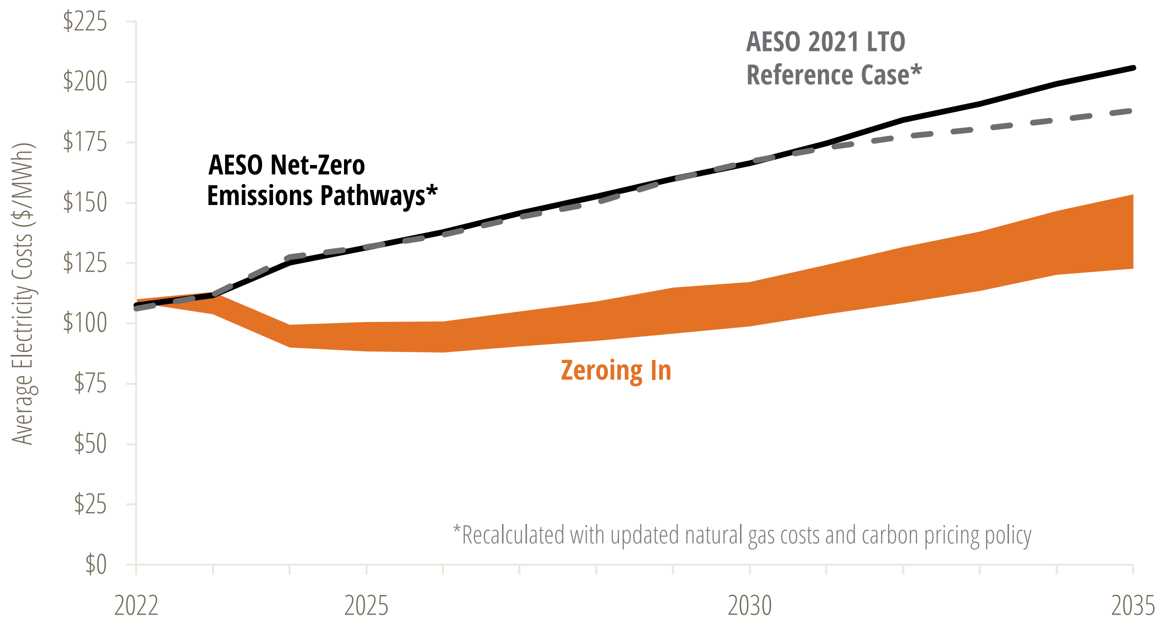

Figure 14. Comparison of modelled annual electricity system costs with previous AESO analyses

Data source: AESO[52]

Reduced consumer costs

All scenarios reduce consumer costs from 2022 electricity cost levels, saving Alberta households hundreds of dollars per year (Figure 15). Residential electricity prices in 2035 under four of six scenarios would be lower than the actual prices in 2022 by 17–24%. Only by adding a large deployment of energy storage, CCS for combined-cycle facilities, and intertie capacity between Alberta, British Columbia and Montana do costs approach 2022 levels by 2035.

[52] *AESO Net-Zero Emissions Pathways Report.*

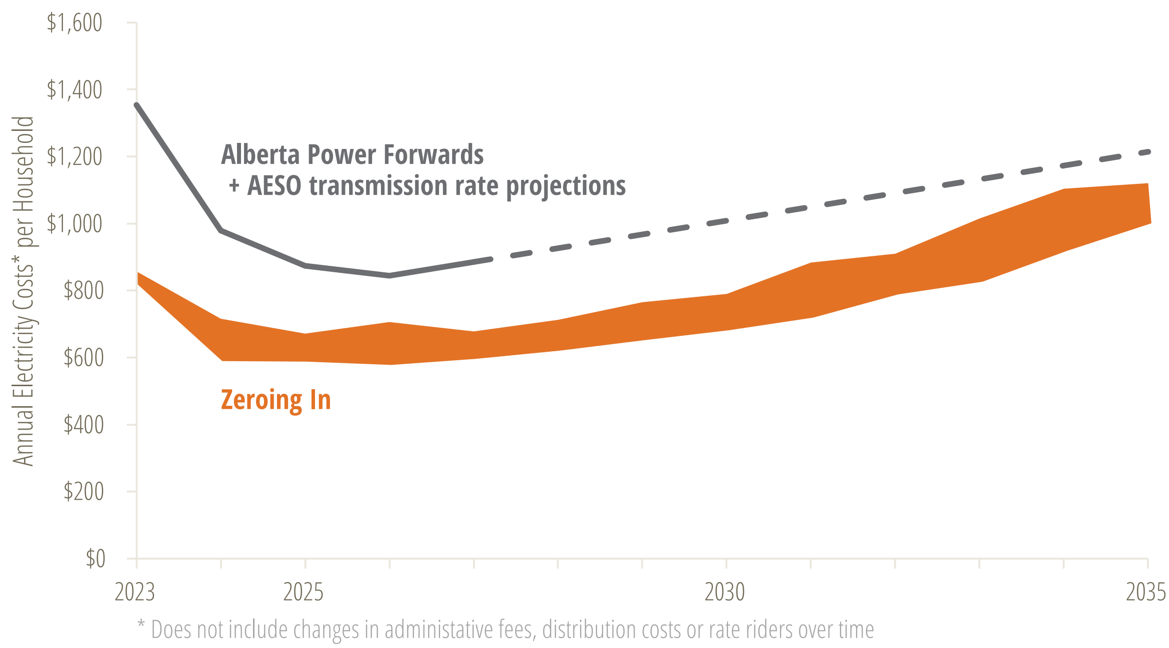

Figure 15. Comparison of modelled household electricity costs with actual and predicted costs

Data source: Alberta Market Surveillance Administrator[53], AESO[54]

Figure 16 shows that from a consumer perspective, the energy price depressing effect from the rapid expansion of wind and solar would be enough to offset the cost of the other measures included in our modelling scenarios (expanding and maintaining interprovincial transmission infrastructure; doubling or tripling the intra-provincial transmission capacity; and investment into non-wires alternatives, such as energy storage). All scenarios predict household electricity costs lower than actual 2022 costs.

Increased storage capacity (the *High Storage* scenario) would provide the lowest-cost electricity for residential consumers in 2035. Energy storage helps reduce system costs by improving the utilization of renewable assets, through decreased curtailment, and replacing gas generation during high-demand high-price hours. Though not explicitly modelled for this work, energy storage can also provide several auxiliary services,

[53] Alberta Market Surveillance Administrator, *Q1 2023 Quarterly Report* (2022), 74. https://www.albertamsa.ca/assets/Documents/Q1-2023-Quarterly-Report.pdf

[54] Alberta Electric System Operator, *Transmission Rate Projection* (2022). https://www.aeso.ca/assets/Uploads/AESO-2022-TRP-Fact-Sheet-FINAL-V3.pdf

historically provided by natural gas and coal generators. The addition of energy efficiency programs[55] and demand-side management would increase savings further.

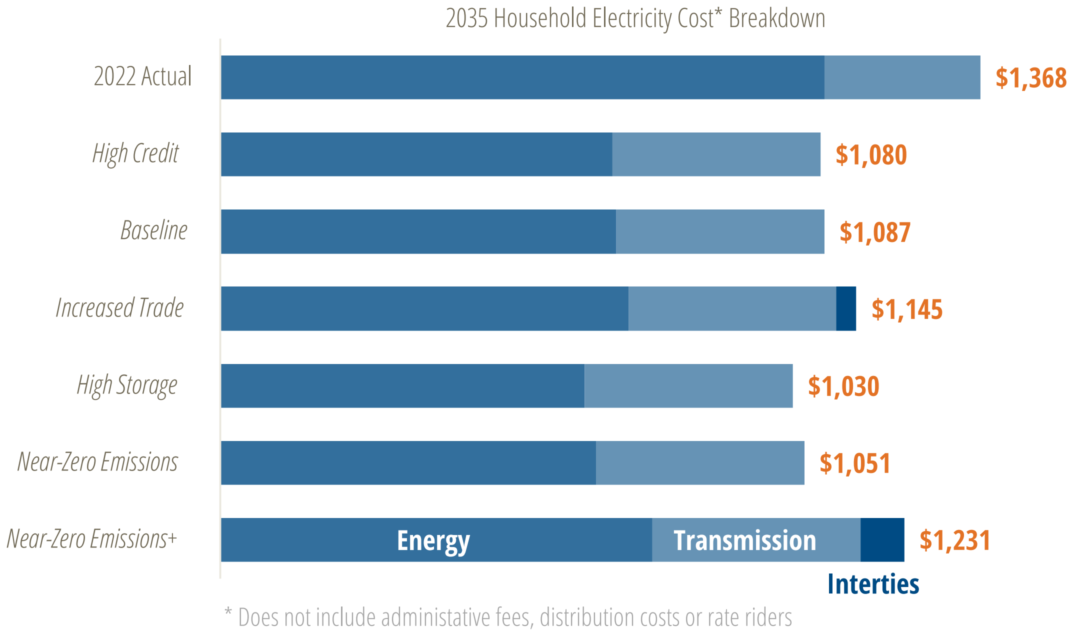

Figure 16. Contributing factors in 2035 household cost estimates by scenario

Growth in energy commodity and export opportunities

All scenarios result in Alberta — which historically has imported more electricity than it exports — becoming a net exporter of clean electricity (Figure 17). Rapid expansion of its wind and solar fleets allows Alberta to serve the majority of its internal electricity demand with renewable energy, exporting the excess to British Columbia and Montana (Figure 18).

[55] For example, the Canada Greener Homes Grant and EnerGuide ratings for products, vehicles, and homes. Source: Natural Resources Canada, "Energy Efficiency," (2023). https://natural-resources.canada.ca/energy-efficiency/10832

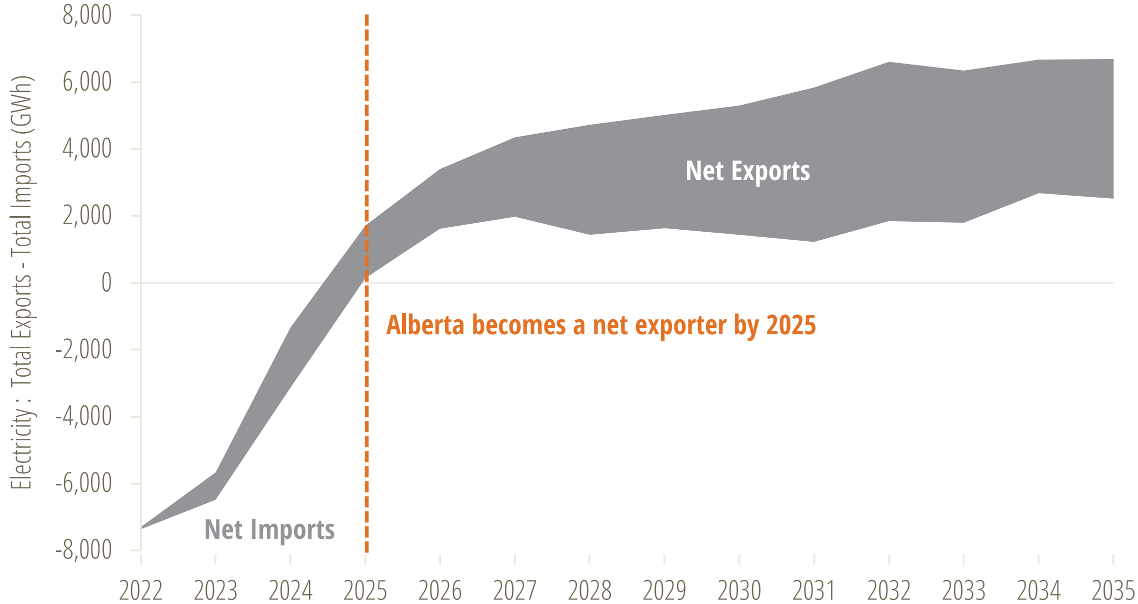

Figure 17. Modelled range of net electricity exports, 2022-2035

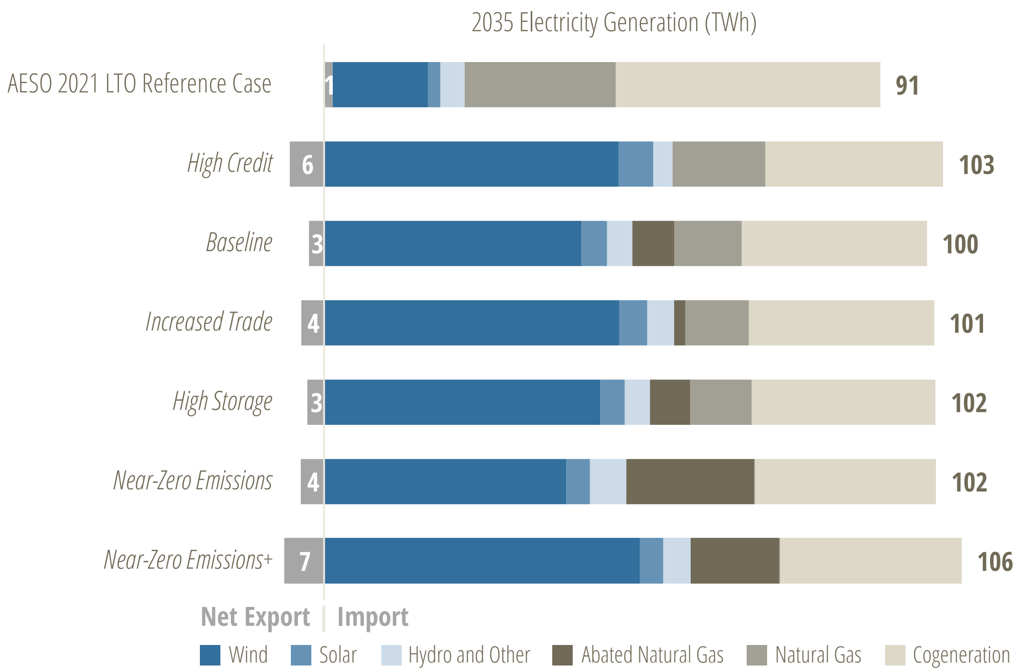

Figure 18. Comparison of 2035 electricity generation by scenario

5.2 Emission reductions

Alberta's electricity grid has already decarbonized faster than anyone anticipated. As Section 2.2 demonstrates, the results and recommendations of Pembina Institute's previous two analyses (in 2009 and 2014) of grid decarbonization in Alberta — which were critiqued at the time for being too ambitious — have already been exceeded.

All six of our scenarios show a continued momentum toward electricity grid decarbonization through different combinations of evolving electricity policies and future generating mix. All scenarios have lower emissions than the AESO 2021 Long-term Outlook *Reference Case*. However, residual emissions remain on the grid (Figure 19). While these emissions will be subject to a carbon price of at least \$170/tCO_2e, additional measures would be needed to credibly remove these residual emissions in order to qualify the grid as net-zero emitting.

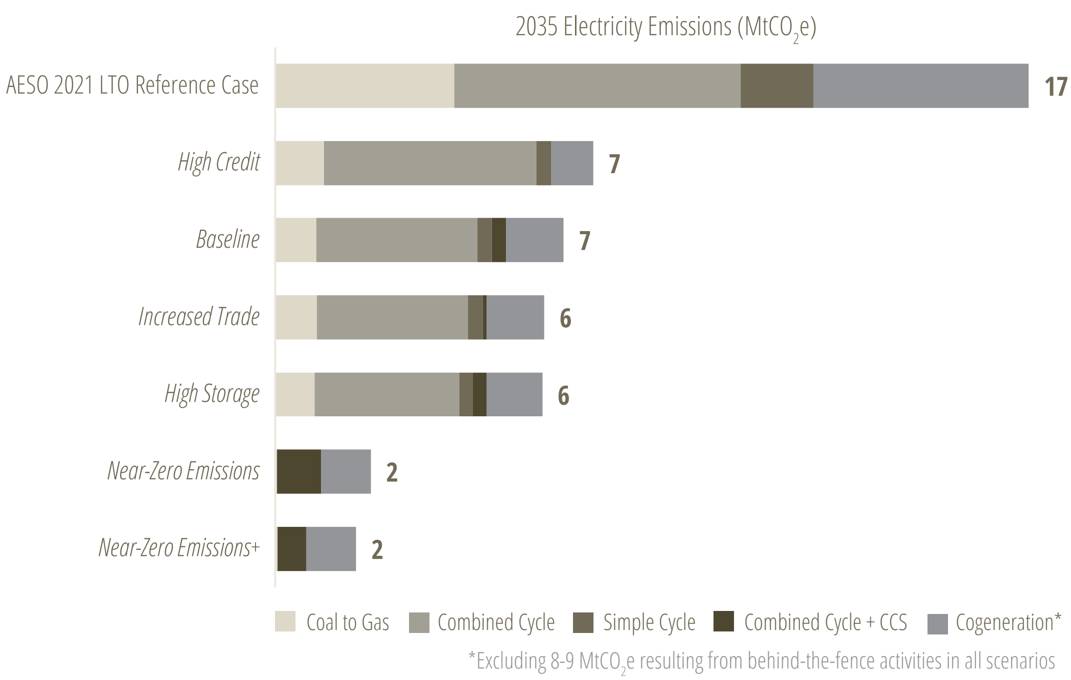

Figure 19. Comparison of 2035 electricity emissions by scenario[56]

[56] Due to differences in reporting criteria, behind-the-fence cogeneration emissions for the AESO 2021 LTO *Reference Case* were estimated using our assumed emissions factor of 0.299 tCO_2e/MWh (see Appendix B.1 for details).

Effects of technology choice

The model is conservative in terms of the technologies it employs, relying largely on commercially available and widely deployed technologies. While better technologies, such as longer-term storage, may become viable in the future and may help reduce emissions further than the forecasts and more economically, most of the technologies in the analysis are considered safe bets and should be invested in significantly and immediately.

The most cost-effective path forward is to invest heavily in renewable energy development. Under current and evolving carbon pricing policies, our analyses suggests that the most economic generating fleet in Alberta consists of a mixture of wind, solar, storage, and existing natural gas assets (Figure 20). Across all scenarios, significant emissions reduction is achieved through large installed capacities of additional wind (10.7–19.3 GW) and solar (2.6–3.1 GW), all while maintaining an affordable, reliable grid.

Strategic deployment of carbon capture plays a critical role in reducing emissions past 6–7 $MtCO_2e$ (both the Near-Zero Emissions scenarios). However, a combination of in-province energy storage and expanded interties (the *Near-Zero Emissions+* scenario) would achieve similar emissions reductions with 3.3 GW less carbon capture.

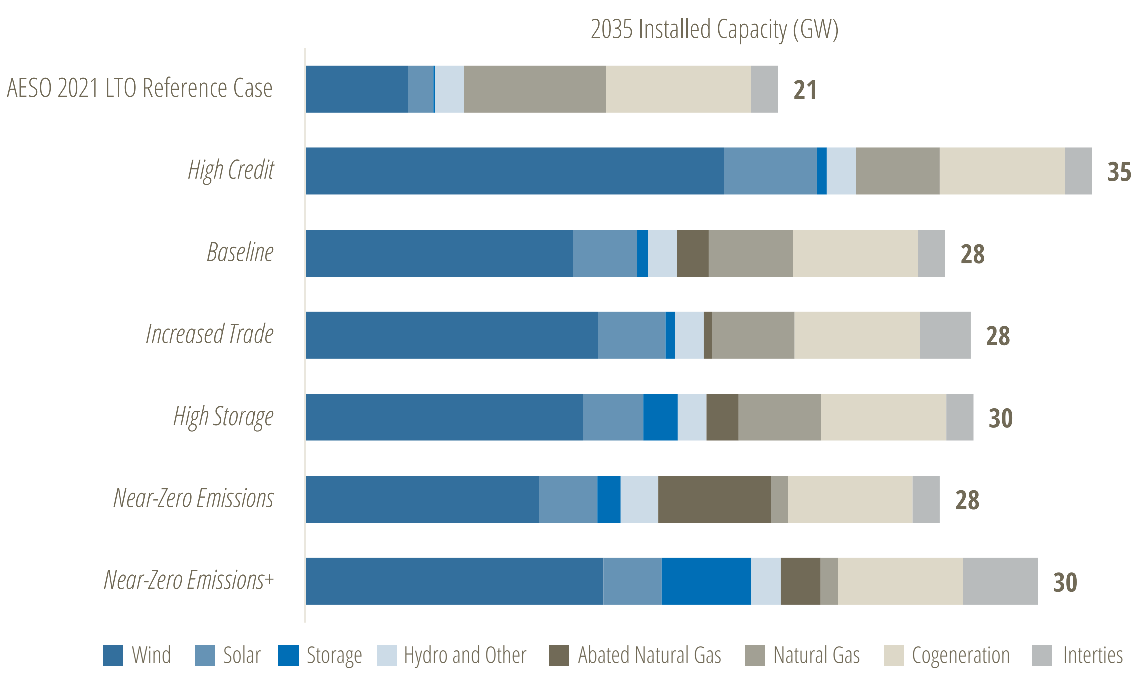

Figure 20. Comparison of 2035 installed capacity by scenario

Effects of electricity emission policy

As the carbon pricing scheme gets more effective emissions will reduce significantly, but carbon pricing alone is not enough to get to a near-zero emitting grid. Reducing the TIER electricity high performance benchmark to zero, as is expected to happen given the trajectory of carbon pricing policy, results in greater carbon capture and lower emissions from gas-fired generation than if the benchmark did not decline (*Baseline* scenario). However, in order to reduce emissions further, additional measures are required that will result in the deployment of greater energy storage, interties, and strategic use of gas-fired generation with carbon capture.

Future treatment of cogeneration emissions

Additional policy measures will also be needed to reduce emissions from natural gas cogeneration. In all scenarios, electricity produced and consumed behind-the-fence at these facilities result in 8 Mt of emissions on the grid and between 30% and 32% of the electricity generated in Alberta in 2035 (Figure 21). This cannot be ignored. Most electricity sector policies (including the Clean Electricity Regulations and TIER for electricity) do not consider emissions from the electricity generated and consumed behind-the-fence. It is critical that there are separate policies specific to emissions reductions in the oil and gas sector.

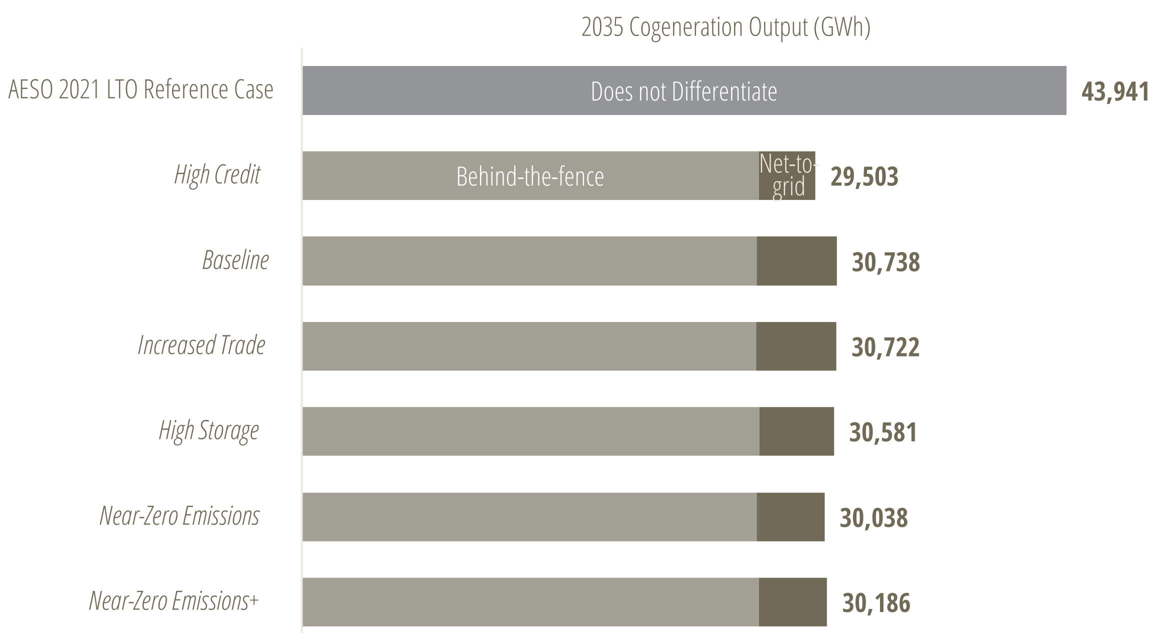

Figure 21. Comparison of 2035 cogeneration output between scenarios

6. Recommendations

A net-zero electrical grid is critical for achieving a net-zero economy. Achieving net-zero will provide environmental, social, and economic benefits for Albertans. To maximize these benefits, the Pembina Institute recommends the following:

1. **Alberta should develop and commit to a net-zero grid by 2035 plan**. As provincial and territorial governments manage their own electricity systems, they play a key role in enabling the nation-wide net-zero transition. Committing to achieving net-zero electricity by 2035 will provide policy certainty to generators, investors, and system planners, driving growth in renewable energy and energy storage development with the lowest financing costs and the best outcome for consumers.
2. **Ensure an affordable transition and a reliable electricity grid through low-cost proven solutions and technologies:**
   - **Enable the continued deployment of technologies such as renewable energy and battery storage.** Wind and solar, especially when paired with battery storage, are the most cost-effective solutions for a reliable electricity grid. Government support, both financial and through enabling policies and regulations, for these technologies will accelerate the transformation. Support is also needed to de-risk early investments in the strategic deployment of longer-term storage[57] to help push Alberta to near-zero electricity emissions by 2035.
   - **Enable energy efficiency and demand response programs.** Though not included in our modelling, enabling demand response and energy efficiency would reduce costs further and provide additional grid reliability services.
   - **Deploy carbon capture solutions carefully.** Carbon capture of residual emissions will be necessary to reach the final net-zero goal. However, overdependence on carbon capture technologies in the electricity sector could inflate costs and divert resources from other sectors that are more difficult to decarbonize (e.g. steel and cement manufacturing).

[57] While there is some ambiguity to the definition of what separates long-term and short-term energy storage, recent research has shown the importance of low-cost energy storage capable of sustaining output for over 100 hours before needing to be recharged. Proactive policy support for early adopters of these technologies is needed until experience drives down costs. Source: Jesse D. Jenkins and Nestor A. Sepulveda, "Long-duration energy storage: A blueprint for research and innovation," *Joule* 5, no. 9 (2021), 2245-2246. https://doi.org/10.1016/j.joule.2021.08.002

3. **Facilitate provincial cooperation on interties**. Interties are a cost-effective way to provide grid reliability services between jurisdictions, especially those with different electricity generation mixes. Increasing intertie capacity between provinces can also improve utilization of existing renewable energy assets while decreasing the need for future expansion of fossil fuel generation. Interties will also allow Alberta to capitalize on its nation-leading wind and solar resources and grow energy export opportunities. Collaboration between provincial (and U.S. state) governments and financial support from the federal government is needed to enable these large inter-jurisdictional infrastructure projects to proceed.
4. **Develop and maintain policy certainty:**
   - **Develop and implement a robust Clean Electricity Regulation (CER).** To be effective in helping Canada achieve its goal of net-zero electricity by 2035, the CER needs to be ambitious and stringent to encourage clean energy investments.
   - **Maintain carbon pricing and lower the electricity high-performance benchmark to zero by 2035.** Our analysis shows that, while it is not enough to reach net-zero electricity on its own, increasing the carbon price and lowering the high-performance benchmark is highly effective for lowering electricity emissions, as well as emissions outside of the electricity sector.[58]
5. **Ensure an equitable opportunity to benefit.** The development of a net-zero grid will require a large capacity of skilled labour and expertise and can usher in greater local economic development. Governments can enable equitable participation across various communities and the workforce with access to permanent, good-paying employment with opportunities for advancement, particularly for those who are currently facing systemic inequalities that continue in the Canadian energy sector.

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[58] Scott MacDougall, *Pembina Institute Input to Government of Alberta's 2022 TIER Review: Comments and recommendations* (Pembina Institute, 2022). https://www.pembina.org/reports/input-to-alberta-2022-tier-review.pdf

Appendix A. Energy model inputs and assumptions

A.1 General simulation parameters

The following assumptions were applied to all scenarios presented in this report.

- **Emissions credits** are generated by wind and solar, with a credit value ($/MWh) equal to the carbon price ($/tCO$_2$e) multiplied by the High-Performance Benchmark for the given year (tCO$_2$e/MWh).
- Unless otherwise specified, **intertie capacity** is maintained at 1,100 MW with British Columbia (BC) and Montana (MT), and 153 MW with Saskatchewan (SK).
- To save on computation time, **connecting markets** (BC, MT, and SK) are not modelled independently. Instead, they are treated as a combined-cycle natural gas units (one for SK, one for BC/MT) whose marginal cost provides a price signal to import or export.
- **Hydrogen** generation is assumed to be zero-emissions. New unabated combined-cycle and simple-cycle plants may elect to use hydrogen as their fuel source.
- **Demand-side management** or **demand response** are only performed when no other supply options are available.
- Alberta's electricity market imposes **transmission costs** on consumers not generators, and therefore they are not directly factored into system optimization. Rather, transmission costs have been added post-modelling, using values provided in AESO's Net-Zero Emissions Pathways Report.
- **Alberta Internal Load (AIL)** data are taken from AESO's Net-Zero Emissions Pathways forecast, which include projected load impacts from **electrification** and **distributed generation**.
- **Hourly demand shape** is based on AIL values from 2021 AESO data.
- **Reserve margin** is maintained at a minimum of 6.5% for all hours.
- **Economic wind fleet expansion** is limited to 2,000 MW per year.[59] **Annual provincial fleet retirement** is limited to 3,000 MW.

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[59] Economic expansion refers to any resources that are added by the model during the capacity expansion portion of the simulation. This limit does not include any assets that were manually entered by the modelling team (e.g., plants that are currently under construction).

- **Geothermal** and **small modular reactors** are not included in this analysis, due to uncertainties in capital cost and timeline of deployment. These technologies may play a role in a decarbonized grid and have applications for behind-the-fence as well.

A.2 Treatment of existing resources

Power plants that are currently operating, and those that have met the project inclusion criteria in AESO's Connection Project List[60] as of March 2023, are considered *existing* resources and are subject to the following conditions.

- Regardless of technology, resources with an **announced retirement** are forced to retire on the prescribed date. All other retirements are economic, as determined by the capacity expansion model.
- **Cogeneration** assets earn revenue outside the electricity market, providing electricity and steam to the industrial processes to which they are linked. As such, they are not considered for **economic expansion** or **retirement**, and their behind-the-fence emissions are considered separately from their grid-related emissions. Emissions intensity of cogeneration facility are held constant in all the analyses, as the factors impacting the deployment of carbon capture in oilsands is outside the scope of this report.
- Thermal assets (simple cycle, combined cycle, cogeneration, coal, and coal-to-gas) are assigned **bidding behaviours** based on historical data. Wind and solar are forced to offer their power at $0/MWh.
- **Wind** and **solar** assets operate based on historic performance or, if generation data is limited, using the Canadian Wind Atlas and Canadian Weather Energy and Engineering Datasets.
- **Energy storage** is dispatched on a **price** basis, providing short-term energy arbitrage.

[60] Alberta Electric System Operator, "Connection Project List." https://www.aeso.ca/grid/transmission-projects/connection-project-reporting/

A.3 New resource options

Table 3. New resource options for future expansion of Alberta's electricity mix

Plant Type	Capacity (MW)	Heat Rate (GJ/MWh)	Operational Lifetime (years)
Hydroelectric (run-of-river)	100	-	40
Combined cycle	418	6.79	20
Combined cycle + CCS	377	7.52	20
Simple cycle (Aeroderivative)	105	9.68	20
Simple cycle (Frame)	233	10.45	20
Biomass	50	-	30
Solar PV*	≤ 100	-	30
Battery storage*	≤ 100	0.88	12–20
Compressed air storage	100	0.52	20
Pumped hydro storage	150	0.8	30
Wind*	≤ 200	-	30

* New wind, solar and battery storage resources are allowed partial builds. All other plant types must build their full capacity to be considered during capacity expansion.

A.4 Economic inputs

Table 4. Operating and maintenance costs for new and existing plants

Plant Type	Fixed O&M* ($/MW-week)	Variable O&M* ($/MWh)	Source
Hydroelectric (reservoir)	Existing: 616	Existing: 2.82	Existing: Default value
Hydroelectric (run-of-river)	New: 788	New: 0	New: AESO NZ Pathways**
Coal	Existing: 1,363	Existing: 10.29	Existing: Default value
Coal-to-gas steam boiler	Existing: 464	Existing: 6.69	Existing: Default value
Cogeneration	Existing: 791	Existing: 7.70	Existing: Default value
Combined cycle	Existing: 791 New: 1,058	Existing: 7.70 New: 2.75	Existing: Default value New: AESO NZ Pathways
Combined cycle + CCS	New: 712	New: 7.93	New: AESO NZ Pathways
Simple cycle	Existing: 551 New: 577	Existing: 21.81 New: 5.51	Existing: Default value New: AESO NZ Pathways
Biomass	Existing: 1,472 New: 1,150	Existing: 4.00 New: 5.02	Existing: Default value New: Default value
Solar PV	Existing: 656 New (2022): 487 New (2035): 470	Existing: 0 New: 0	Existing: Default value New: CEC Renewables***
Battery storage	Existing: 206 New (2022): 279 New (2035): 226	Existing: 5.02 New: 0.68	Existing: Default value New: CEC Renewables
Compressed air storage	New: 404	New: 0.68	New: AESO NZ Pathways
Pumped hydro storage	New: 769	New: 0.68	New: AESO NZ Pathways
Wind	Existing: 624 New (2022): 673 New (2035): 614	Existing: 3.66 New: 0	Existing: Default value New: CEC Renewables

* All values given in 2022 C$

** Alberta Electric System Operator, *AESO Net-Zero Emissions Pathways Report* (2022). https://www.aeso.ca/assets/AESO-Net-Zero-Emissions-Pathways-Report-July7.pdf

*** Clean Energy Canada, *A Renewables Powerhouse* (2023). https://cleanenergycanada.org/report/a-renewables-powerhouse/

Table 5. Capital costs and carrying factors for new plants

Plant Type	Capital Cost* ($/kW)	Capital Carrying Factor	Source
Hydroelectric	14,545	6.61%	AESO NZ Pathways**
Combined Cycle	2022: 1,841 2035: 1,695	8.69%	AESO NZ Pathways
Combined Cycle + CCS	2022: 3,370 2035: 2,804	8.69%	AESO NZ Pathways
Simple Cycle (Aeroderivative)	2022: 1,280 2035: 1,128	8.69%	AESO NZ Pathways
Simple Cycle (Frame)	2022: 992 2035: 874	8.69%	AESO NZ Pathways
Biomass	2022: 7,944 2035: 7,202	7.23%	Default Value
Solar PV	2022: 1,699 2035: 1,282	7.23%	CEC Renewables***
Battery Storage (10 MW, 4 hour)	2022: 2,244 2035: 1,374	8.69%	AESO NZ Pathways
Battery Storage (100 MW, 4 hour)	2022: 2,449 2035: 1,384	11.9%	CEC Renewables
Battery Storage (100 MW, 6 hour)	2022: 3,609 2035: 2,020	11.9%	CEC Renewables
Battery Storage (100 MW, 8 hour)	2022: 4,767 2035: 2,655	11.9%	CEC Renewables
Compressed Air Storage	1,585	8.69%	AESO NZ Pathways
Pumped Hydro Storage	3,493	7.23%	AESO NZ Pathways
Wind	2022: 1,710 2035: 1,169	7.23%	CEC Renewables

* All values given in 2022 C$

** Alberta Electric System Operator, *AESO Net-Zero Emissions Pathways Report* (2022). https://www.aeso.ca/assets/AESO-Net-Zero-Emissions-Pathways-Report-July7.pdf

*** Clean Energy Canada, *A Renewables Powerhouse* (2023). https://cleanenergycanada.org/report/a-renewables-powerhouse/

Appendix B. Additional analyses

Calculations presented in this section were performed by the Pembina Institute and have no affiliation with the University of Alberta modelling team.

B.1 Differences in Pembina Institute and AESO assumptions

There are significant differences in input costs, policy assumptions, and emissions reporting between our modelling and those published by AESO in their 2021 Long-term Outlook (LTO) and Net-Zero Emission Pathways (NZP) work. The differences in inputs most notably include forward-looking natural gas prices, carbon pricing policies, and cogeneration emissions reporting. To provide a level playing field in comparing our analyses with AESO's, we estimate the impact made by these differences and apply incremental adjustments to annual operating costs and cogeneration emissions to those published in the LTO and NZP reports. Figure 22 shows future electricity costs as published in AESO's NZP report. Figure 1 shows the updated costs, including the incremental impact of updated natural gas and carbon pricing policies.

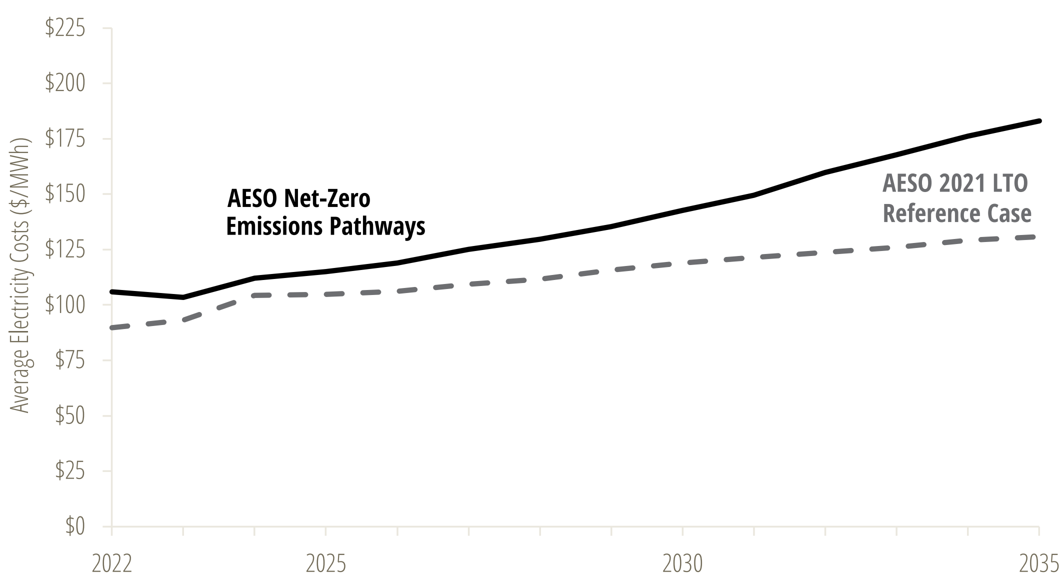

Figure 22. Annual electricity system costs published in previous AESO analyses

Data source: AESO[61]

[61] *AESO Net-Zero Emissions Pathways Report*, 71.

B.1.1 Natural gas prices

Price forecasts, especially for volatile globally priced commodities, are inherently inaccurate. The purpose of this analysis is to highlight the potential risk of under-predicting future natural gas prices and quantify its impact on electricity system costs under different generation mixes.

Incremental fuel costs for natural gas plants ($/year) were accounted for by multiplying annual fuel consumption (GJ/year) by the difference between AESO's and our gas price assumptions ($/GJ). Fuel consumption was approximated by multiplying average net heat rates for each plant type (GJ/MWh), provided in Table 3, by their annual generation (MWh/year), taken from the LTO and NZP datafiles.[62,63]

$$\text{Fuel Consumption per Plant Type} = \text{Average Heat Rate} * \text{Generation}$$

$$\text{Incremental Fuel Cost} = (\text{Pembina Fuel Price} - \text{AESO Fuel Price}) * \text{Total Fuel Consumption}$$

Between 2022 and 2035, these incremental adjustments to natural gas prices resulted in an additional $18.3 billion in system costs for the LTO *Reference Case* and $13.8 billion for the NZP *Dispatchable Dominant* scenario.[64] These incremental costs account for a 20% increase in cumulative LTO system costs and a 13% increase in the NZP *Dispatchable Dominant* scenario. Annual inputs and intermediate results of this analysis are provided for selected years in Table 6.

[62] Alberta Electric System Operator, "Datafile | 2021 Long-term Outlook data file," 2021. https://www.aeso.ca/grid/grid-planning/forecasting/2021-long-term-outlook/

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

[64] Due to its decreased reliance on natural gas-fired generation, sensitivity to natural gas prices is partially mitigated in the NZP *Renewables and Storage Rush* scenario, which would save $2.4 billion in incremental natural gas costs relative to the *Dispatchable Dominant* scenario.

Table 6. Impact of natural gas price assumptions in past AESO analyses

Parameter	Year		
	2025	2030	2035
Natural Gas Price ($/GJ)			
Zeroing In*	4.353	5.428	6.049
AESO 2021 LTO *Reference Case*	2.409	2.955	3.300
AESO NZP, *Dispatchable Dominant*	2.969	3.364	3.751
Cogeneration Output (GWh)			
AESO 2021 LTO *Reference Case*	39,920	42,192	43,941
AESO NZP, *Dispatchable Dominant*	41,891	43,542	45,747
Coal-to-gas Output (GWh)			
AESO 2021 LTO *Reference Case*	9,780	8,430	6,342
AESO NZP, *Dispatchable Dominant*	8,946	483	921
Combined-cycle Natural Gas Output (GWh)			
AESO 2021 LTO *Reference Case*	16,695	15,906	15,856
AESO NZP, *Dispatchable Dominant*	13,670	5,891	4,654
Simple-cycle Gas Turbine Output (GWh)			
AESO 2021 LTO *Reference Case*	2,681	2,596	2,943
AESO NZP, *Dispatchable Dominant*	3,313	1,120	914
Combined-Cycle Natural Gas with CCS Output (GWh)			
AESO NZP, *Dispatchable Dominant*	0	18,979	17,503
Total Natural Gas Consumption (million GJ)			
AESO 2021 LTO *Reference Case*	579	574	575
AESO NZP, *Dispatchable Dominant*	565	582	575
Incremental Fuel Cost ($ million)			
AESO 2021 LTO *Reference Case*	1,126	1,420	1,564
AESO NZP, *Dispatchable Dominant*	782	1,201	1,323

*Indexed to Henry Hub natural gas prices

B.1.2 Carbon pricing policy

Incremental emissions costs ($/year) were accounted for by taking the difference between total emissions costs under Pembina Institute and AESO carbon policy assumptions. The volume of emissions that are exposed to carbon pricing (tCO_2e/year) for each plant type were estimated by multiplying total generation (MWh/year), provided in Table 7, by the TIER high-performance benchmark (HPB) (tCO_2e/MWh) and subtracting that from the total emissions published in the LTO and NZP datafiles (tCO_2e/year).[65,66] Annual emissions costs are then found by multiplying the result by the carbon price ($/$tCO_2e$) for the given year.

$$\text{Exposed Emissions per Plant Type} = \text{Reported Emissions} - (\text{Generation} * \text{TIER HPB})$$

$$\text{Emissions Costs} = \text{Sum of Exposed Emissions} * \text{Carbon Price}$$

$$\begin{aligned}\text{Incremental Emissions Costs}& \\ &= \text{Emissions Costs (Pembina Assumptions)} \\ &- \text{Emissions Costs (AESO Assumptions)}\end{aligned}$$

Between 2022 and 2035, our incremental adjustments to emissions prices resulted in an additional $15.1 billion in system costs for the LTO *Reference Case* and $3.2 billion for the NZP *Dispatchable Dominant* scenario. These incremental costs account for a 17% increase in cumulative LTO system costs and a 3% increase in the NZP *Dispatchable Dominant* scenario. Annual inputs and intermediate results of this analysis are provided for selected years in Table 7.

Table 7. Impact of carbon policy assumptions in past AESO analyses

Parameter	Year		
	2025	2030	2035
Carbon Price ($/$tCO_2e$)			
Zeroing In	95	170	170
AESO 2021 LTO *Reference Case*	53	59	65
AESO NZP, *Dispatchable Dominant*	95	170	170

[65] “Datafile | 2021 Long-term Outlook data file.”

[66] “Excel | AESO Net-Zero Emissions Pathways Data File.”

TIER High-performance Benchmark for Electricity (tCO_2e/MWh)			
Zeroing In	0.285	0.142	0.000
AESO 2021 LTO *Reference Case*	0.370	0.370	0.370
AESO NZP, *Dispatchable Dominant*	0.359	0.341	0.325
Total Coal-to-gas Emissions ($MtCO_2e$)			
AESO 2021 LTO *Reference Case*	6.7	5.9	4.2
AESO NZP, *Dispatchable Dominant*	5.7	0.4	0.7
Total Combined-cycle Natural Gas Emissions ($MtCO_2e$)			
AESO 2021 LTO *Reference Case*	7.0	6.7	6.7
AESO NZP, *Dispatchable Dominant*	5.6	2.6	2.1
Total Simple-cycle Gas Turbine Emissions ($MtCO_2e$)			
AESO 2021 LTO *Reference Case*	1.6	1.5	2.1
AESO NZP, *Dispatchable Dominant*	1.7	0.7	0.6
Emissions Subject to Carbon Pricing under AESO Assumptions ($MtCO_2e$)			
AESO 2021 LTO *Reference Case*	4.5	4.2	3.3
AESO NZP, *Dispatchable Dominant*	3.7	1.1	1.2
Emissions Subject to Carbon Pricing under Pembina Assumptions ($MtCO_2e$)			
AESO 2021 LTO *Reference Case*	7.0	10.3	12.6
AESO NZP, *Dispatchable Dominant*	5.7	2.6	3.3
Incremental Emissions Cost ($ million)			
AESO 2021 LTO *Reference Case*	427	1,509	1,930
AESO NZP, *Dispatchable Dominant*	183	254	337

B.1.3 Cogeneration emissions reporting

In their analyses, AESO only includes cogeneration emissions for assets that are "primarily engaged in the generation of bulk electric power," as identified by North American Industry Classification System (NAICS) code 221112 – Fossil-fuel electric power generation.[67] In other words, they do not include emissions from integrated facilities that are primarily engaged in activities outside the electricity sector, which account for over 80% of existing (as of 2023) cogeneration capacity.

To account for the incremental electricity emissions from the facilities that are not included in AESO's reporting, we estimate an electricity-only emissions factor using historic facility-level emission data, where steam emissions are estimated using an assumed emissions factor for industrial heat (0.06299 tCO_2e/GJ).[68] Emissions resulting from electricity production (tCO_2e) are then found by subtracting steam emissions (tCO_2e) from total emissions (tCO_2e). The electricity emissions factor (tCO_2e/MWh) is the ratio of electricity emissions to total electricity production (MWh). Between 2011 and 2019 the average electricity emissions factor for cogeneration facilities was found to be 0.299 tCO_2e/MWh, as shown in Table 8.

$$\text{Steam Emissions} = \text{Cogeneration Heat} * \text{Industrial Heat Emissions Factor}$$

$$\text{Electricity Emissions} = \text{Total Cogeneration Emissions} - \text{Steam Emissions}$$

$$\text{Electricity Emissions Factor} = \text{Electricity Emissions}/\text{Electricity Production}$$

[67] This methodology is in alignment with the records collected through the Government of Canada's Greenhouse Gas Reporting Program. *AESO Net-Zero Emissions Pathways Report*, 49.

[68] Government of Alberta, *Emissions Management and Climate Resilience Act: Technology Innovation and Emissions Reduction Regulation* AR 133/2019 Sched 2;132/2020;251/2022. https://kings-printer.alberta.ca/documents/Regs/2019_133.pdf

Table 8. Estimated electricity emission factor for cogeneration assets

Year	Reported Cogeneration Facility Data*			Estimated Electricity Emission Factor (tCO_2e/MWh)
	Total Emissions ($MtCO_2e$)	Heat Produced (million GJ)	Electricity Produced (GWh)	
2011	10.9	107	12,955	0.318
2012	11.7	123	14,238	0.279
2013	14.0	145	16,749	0.288
2014	15.4	154	17,737	0.318
2015	16.2	162	18,450	0.323
2016	15.5	161	17,860	0.300
2017	16.7	179	19,594	0.280
2018	19.1	197	22,043	0.302
2019	19.1	203	22,743	0.281
Average Electricity Emission Factor for Cogeneration Facilities				**0.299 tCO_2e/MWh**

*Data source: Alberta Environment and Parks[69]

In 2035, these incremental emissions account for a 46% (8.1 Mt) increase to LTO electricity emissions and a 392% (13.2 Mt) increase in the NZP *Dispatchable Dominant* scenario. Assuming that the behind-the-fence generation at cogeneration facilities accounts for between 25% and 35% of system load,[70] 2035 net-to-grid emissions are estimated to be 16.7 Mt for the LTO and 8.6 Mt for the NZP *Dispatchable Dominant* scenario. Annual inputs and intermediate results of this analysis are provided for selected years (Table 9).

[69] Alberta Environment and Parks, "Alberta Oil Sands Greenhouse Gas Emissions Intensity Analysis," 2019. https://open.alberta.ca/opendata/alberta-oil-sands-greenhouse-gas-emission-intensity-analysis#summary

[70] In alignment with AESO's estimation of system load as 65% to 75% of Alberta Internal Load. Source: *AESO Net-Zero Emissions Pathways*, 71.

Table 9. Impact of cogeneration emissions reporting in past AESO analyses

Parameter	Year		
	2025	2030	2035
Cogeneration Output (GWh)			
Zeroing In, *Baseline*	30,525	30,821	30,738
AESO 2021 LTO *Reference Case*	39,920	42,192	43,941
AESO NZP, *Dispatchable Dominant*	41,891	43,542	45,747
Reported Cogeneration Emissions ($MtCO_2e$)			
Zeroing In, *Baseline* (Including behind-the-fence)	9.1	9.2	9.2
AESO 2021 LTO *Reference Case*	5.2	5.0	5.1
AESO NZP, *Dispatchable Dominant*	4.6	2.2	0.5
Total Incremental Cogeneration Emissions ($MtCO_2e$)			
AESO 2021 LTO *Reference Case*	6.8	7.6	8.1
AESO NZP, *Dispatchable Dominant*	8.0	10.8	13.2
Total System Emissions, including behind-the-fence ($MtCO_2e$)			
Zeroing In, *Baseline*	17.7	15.9	14.8
AESO 2021 LTO *Reference Case*	27.3	26.8	25.8
AESO NZP, *Dispatchable Dominant*	25.6	17.4	17.7
Estimated Net-to-Grid Emissions ($MtCO_2e$)			
Zeroing In, *Baseline*	9.9	8.1	6.9
AESO 2021 LTO *Reference Case*	18.9	18.0	16.7
AESO NZP, *Dispatchable Dominant*	17.2	8.6	8.6

B.2 Forward-looking residential electricity price and costs per household

In Alberta, electricity charges related to distribution, administration, municipal land access fees, and rate riders will vary based on service area, municipality, and billing period. By focusing exclusively on transmission and energy charges, we can attempt to estimate trends in province-wide residential electricity costs relative to 2022, under the assumption that any increases to the other charges will happen regardless, independent of the scenarios that we are assessing.

In this section, we compare our scenarios to a baseline cost assumption — using Alberta Market Surveillance Administrator (MSA) power forwards[71] and AESO transmission rate projections[72] (see Table 10) — to quantify the relative impact that decarbonization would have on consumer electricity prices, shown in Figure 13.

Table 10. Forward looking electricity prices and transmission rates

Year	Power Forwards* ($/MWh)	Transmission Rate Projection** ($/MWh)
2023	147	41
2024	95	41
2025	80	41
2026	75	41
2027	80	42
2028	84	43
2029	87	44
2030	91	44
2031	95	45
2032	98	46

[71] Power forwards are used as AESO does not publish their pool price results from their electricity market modelling. Data source: Alberta Market Surveillance Administrator, *Q1 2023 Quarterly Report* (2022), 74. https://www.albertamsa.ca/assets/Documents/Q1-2023-Quarterly-Report.pdf

[72] Alberta Electric System Operator, *Transmission Rate Projection* (2022). https://www.aeso.ca/assets/Uploads/AESO-2022-TRP-Fact-Sheet-FINAL-V3.pdf

2033	102	46
2034	106	47
2035	110	48

*Uses 5 years of MSA power forwards, then assumes a 5% increase per year after 2027

**Uses 10 years of AESO transmission projections, then assumes a 1.5% increase in transmission rates after 2032

For our modelled scenarios, future transmission charges ($/MWh) are calculated by dividing transmission revenue requirements ($) and annual intertie costs ($) by system load (MWh).[73] Energy charges are assumed to be equal to our modelled average annual pool price ($/MWh) plus a correction factor ($/MWh) to account for limitations in the modelling software. This correction factor is based on instances in the model where generators are unable to recover their operating costs in the energy market using historic bidding patterns. In this way, we estimate the impact to the modelled pool price if those generators had recovered their costs (plus an expected return on capital) through some other mechanism. Annual inputs and intermediate results of this analysis are provided for selected years in Table 11.

$$\text{Transmission Charge} = \text{Transmission Costs/System Load}$$

$$\text{Energy Charge} = \text{Annual Average Pool Price} + \text{Correction Factor}$$

Table 11. Future electricity price estimations by scenario

Parameter	Year		
	2025	2030	2035
System Load (GWh)			
All Scenarios	64,876	67,637	69,136
Transmission Costs ($ million)			
High Credit	2,495	2,938	3,353
Baseline	2,495	2,938	3,353
Increased Trade	2,822	3,202	3,269

[73] Transmission revenue requirements are assumed to be equal to those from AESO's Net-Zero Emissions Pathways *Renewables and Storage Rush* scenario. *AESO Net-Zero Emissions Pathways Report.*

High Storage	2,495	2,938	3,353
Near-Zero Emissions	2,495	2,938	3,353
Near-Zero Emissions+	3,165	3,546	3,972
Average Pool Price ($/MWh)			
High Credit	32	42	98
Baseline	32	68	94
Increased Trade	32	43	100
High Storage	34	56	82
Near-Zero Emissions	39	44	75
Near-Zero Emissions+	31	28	100
Correction Factor ($/MWh)			
High Credit	15	2	0
Baseline	15	1	4
Increased Trade	15	15	2
High Storage	0	2	0
Near-Zero Emissions	7	12	17
Near-Zero Emissions+	23	30	14
Household Cost* ($/year)			
MSA Power Forwards + AESO Transmission Rate Projections	874	1,009	1,214
High Credit	619	632	1,046
Baseline	604	801	1,049
Increased Trade	642	756	1,110
High Storage	609	742	999
Near-Zero Emissions	600	712	1,004
Near-Zero Emissions+	725	796	1,179

*Assumes an average residential electricity consumption of 7,200 kWh per year

B.3 Intertie cost estimation

In 2015, two 500 kV high-voltage direct-current transmission lines were installed between Edmonton and Calgary, spanning approximately 300 km each. Each line is rated to carry 1,000 MW, and cost between $1.7 billion and $1.9 billion to install.[74] Accounting for inflation, uncertainties around budgeting, and the 10% difference in capacity (i.e. 1,100 MW instead of 1,000 MW), we estimate that the overnight capital cost of doubling the BC/MT intertie is $3 billion.

Applying the U.S. Energy Information Administration's suggested 6.2% weighted after-tax cost of capital,[75] and assuming that the intertie would be financed over the full study duration (i.e. 2023 to 2035), expanding the intertie would cost the province $343 million per year.

[74] Transmission Facilities Cost Monitoring Committee, *Review of the Cost Status of Major Transmission Projects in Alberta* (2015), 32. https://ucahelps.alberta.ca/documents/ABE_TFCMC_REPORT_10_090516_WEB_1.pdf

[75] U.S. Energy Information Administration, *Levelized Costs of New Generation Resources in the Annual Energy Outlook 2022* (2022), 6. https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

B.4 Cost uncertainty of carbon capture for Near-Zero Emissions scenarios

For our analysis, we assume abated combined-cycle natural gas (CCNG) plants cost 40–45% more than unabated plants (Table 5). For example, in 2022, an unabated CCNG plant would cost $1,841/kW, while an abated CCNG plant would cost $3,370/kW. This implies that the CCS portion of the plant costs $1,529/kW or, including the cost of financing with an assumed a 20-year operational life and 8.6% weighted cost of capital, approximately $3,276/kW paid over 20 years.

For comparison, the Boundary Dam coal plant in Saskatchewan cost an estimated $800 million for the CCS process.[76] It has a gross output of 160 MW and, due to the parasitic CCS load, a 110 MW net output. As such, the Boundary Dam CCS project had a capital cost ($5,000/kW net or $7,273/kW gross), which is 1.5 to 2.2 times higher than our input assumptions for that year. As time progresses, and the technology matures, this factor is assumed to decrease accordingly.

Applying the net (1.5-times) factor to the CCS portion of the *Near-Zero Emissions* 5.2 GW abated natural gas fleet would result in a $1.5 billion increase in total system costs by between 2023 and 2035, and $5.9 billion over the useful life of those facilities. Similarly, a 1.5-times increase in CCS capital costs in the *Near-Zero Emissions*+ scenario — which has 1.8 GW in abated natural gas capacity — would result in a $220 million increase in total system costs between 2023 and 2035, and $2.4 billion over the useful life of those facilities.

Similarly, our inputs assume a 10% to 23% parasitic load for CCS equipment. For example, the average full load heat rate for an unabated CCNG plant in 2029 is 7,751 Btu/kWh, while an abated plant from the same year is 8,616 Btu/kWh. As noted above, Boundary Dam has a 50 MW difference between net and gross output, resulting from a 31% parasitic load to run the CCS equipment. Increasing the annual operating costs accordingly results in a $160 million increase in fuel costs for *Near-Zero Emissions* + and a $660 million increase for *Near-Zero Emissions*.

[76] Carbon Capture and Sequestration Technologies, "CCS Project Database: Boundary Dam Fact Sheet," 2016. http://sequestration.mit.edu/tools/projects/boundary_dam.html