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THE ROLE OF HYDROGEN IN DECARBONIZING ALBERTA'S ELECTRICITY SYSTEM

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SUMMARY

In roughly two years, and well ahead of schedule, Alberta is expected to have completely transformed its electrical grid from being largely powered by coal to instead being powered by natural gas, hydroelectricity, wind and solar. By 2030, however, it is likely that another fuel source will compete with natural gas as a major part of Alberta's power grid: namely hydrogen.

Fully decarbonizing Alberta's electric power sector as Canada works to achieve its goal of net-zero greenhouse gas emissions will be challenging due to the lack of significant hydroelectric or any nuclear power in the province. However, Alberta has many advantages that make hydrogen feasible as a pathway to decarbonizing its power grid. First, the steam and combustion turbines that are powered by natural gas today to produce electricity in Alberta can be adapted to use hydrogen. Second, Alberta has vast amounts of natural gas that can be used to produce hydrogen, and ample geology for underground carbon capture and storage for the greenhouse gases emitted in producing hydrogen. And third, in periods where the province's renewable energy sources produce excess electricity, that power can be used to produce hydrogen, which can be stored for later use when renewable energy is less available.

These advantages, combined with certain federal and provincial policies, position hydrogen to play a significant role, providing low-emission firm power when variable solar and wind power are unable to meet the province's power demands. Given the limits of battery storage capacity, cost, and technology beyond hourly & possibly overnight use, storing hydrogen for multi-hour, -day

and seasonal storage in underground, salt caverns appears to be a practical alternative for Alberta.

Absent government policy, hydrogen-based power costs would likely remain uncompetitive in Western Canada, where natural gas is abundant and cheap. However, Alberta's climate policy, with its output-based allocations regime, is set to combine with the federal government's plan to raise the carbon price to $170 per tonne to make all forms of hydrogen-based power production more cost-effective than natural gas in the province after 2030.

The potential for Alberta to transition to a reliable, low-carbon electricity grid will require that any future adjustments to the output-based allocations regime consider the impact on the economics of hydrogen investment and production. The government should also ensure that Alberta reserves its salt caverns for eventual use as hydrogen storage and that any newly installed turbines are capable of being easily retrofitted to use hydrogen as fuel. Hydrogen is an opportunity to bridge today's system, based on fossil fuels, to tomorrow's net-zero fuels and technologies. It is an opportunity that Alberta is well-positioned to seize.

1. INTRODUCTION

Alberta's electricity system is heavily reliant on fossil fuels in its generation mix. To decarbonize the electricity system will require a significant increase in both variable renewable energy, namely wind and solar power, as well as firm low-carbon resources. Hydrogen offers the potential to both absorb excess variable renewable energy and provide a clean source of peaking capacity by its use as a fuel in steam and combustion turbines.

This School of Public Policy Research Paper is intended to provide a wide audience of policy-makers, industry participants, and the interested public an overview of:

1. The potential for hydrogen in the Alberta electricity sector as a long-term energy storage solution and a complement to variable renewable energy;
2. The ability for existing infrastructure to utilize hydrogen fuel;
3. A model comparing the expected costs of hydrogen to existing natural gas over time, including an increasing carbon price to 2030; and
4. A concluding discussion on preparing infrastructure and regulations today for the needs of tomorrow.

The pathway for clean hydrogen is likely to begin in markets where it has the highest value (i.e., where decarbonization alternatives are costly) and in areas of least resistance, namely where existing energy supplies, infrastructure and end-uses can be most easily repurposed for hydrogen use.

Our paper provides a deep dive into one such pathway for clean hydrogen: **decarbonizing electricity production**. For this analysis, we focus on Alberta, a province that has committed to phasing out coal power — previously its dominant fuel type for power generation — by 2030. As coal units retire, the question becomes: what will replace them in a manner consistent with the goal of net-zero emissions?

Natural gas is seen by many as coal's natural successor, at least in the near term. In some cases, this will involve converting coal units to burn natural gas, and in some cases it will involve retrofitting facilities to become highly efficient combined-cycle natural gas units. Given the low price of natural gas in Alberta, the plentiful reserves, and the relatively low cost of repurposing existing coal power infrastructure, natural gas is likely to play a significant role in the province, especially in the near term.

However, to eliminate emissions from the power sector and enable further electrification using renewable electricity, other options will be needed. Growth in variable renewable energy (VRE) is already occurring and this is expected to continue. Given Alberta's relative lack of transmission capacity with neighbouring jurisdictions and barring significant improvements in large-scale energy storage, the challenge will be in the ability to turn this cheap raw energy into the clean and reliable power consumers demand (Sepulveda et al., 2018).

Hydrogen offers a solution to this challenge. Hydrogen can perform the peaking and firming service required to complement VRE: that is, it can provide electricity when wind and solar are unavailable. This can be done by either combusting hydrogen in dual-fuel natural gas/hydrogen turbines or 100-per-cent hydrogen turbines, or transforming it into electricity using fuel cells. Furthermore, in times of strong renewable energy generation, electrolysis facilities can absorb excess electricity, turning water into hydrogen.

Our paper considers ways in which smart planning today can prepare us for the infrastructure and systems needed in the future. The notion of repurposing incumbent infrastructure, be it natural gas distribution and transmission systems or future-proofing coal-to-gas conversions by making them hydrogen-ready, can enable a lower-cost transition with fewer facilities abandoned as stranded assets. Ensuring that pipelines and other infrastructure are prepared for this change can remove future barriers to transition. To do so requires forethought and planning from today's regulators and industry participants.

2. HYDROGEN IN THE ELECTRICITY SECTOR

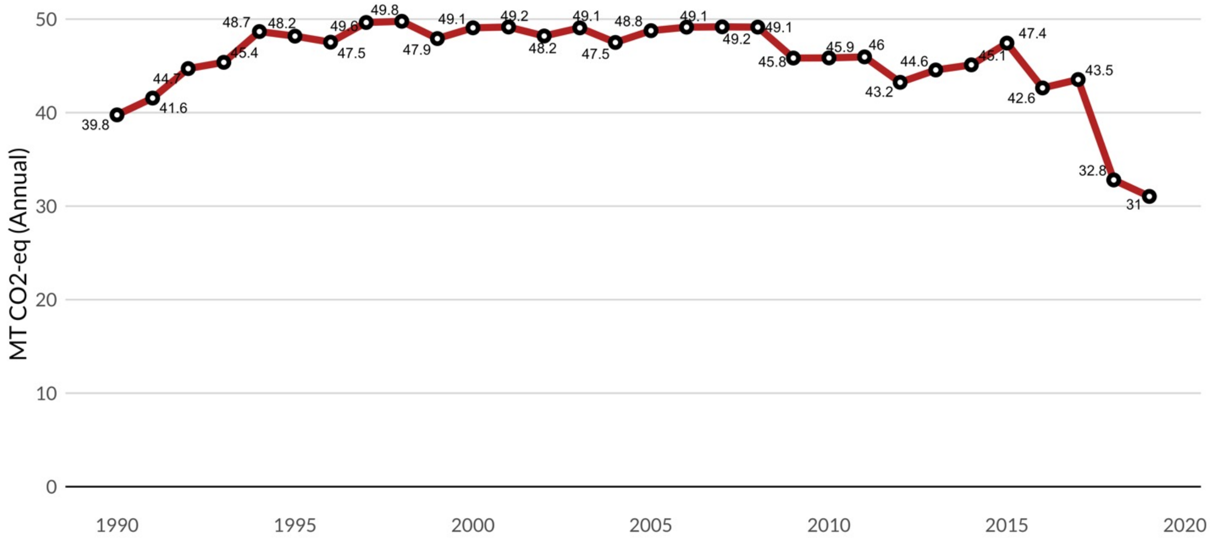
Recent advances in renewable energy technology have made wind and solar renewable energy the cheapest source of electricity on a levelized cost basis in most places (Schumacher et al., 2020; IEA 2020). The challenge is no longer making clean renewable energy cheap, but rather integrating these intermittent resources while maintaining grid reliability when they are unavailable.

Options to "firm" VRE include eliciting greater demand response to reduce peak energy demand, adding storage, expanding transmission connectivity across regions, and installing and/or maintaining peaking generators. To remain consistent with a path to decarbonization, the latter solution — peaking generators — could be fueled by hydrogen. We explore the economic potential to use hydrogen as a firming power source, rather than its broad use as an energy source, relying instead on cheaper renewable energy to fulfill the role of delivering large supplies of raw energy.

2.1 DECARBONIZING ALBERTA'S ELECTRICITY SYSTEM

Unlike most other provinces in Canada, Alberta relies heavily on a fleet of combustion turbines and steam turbines to produce electricity. Combined, these sources produced 31 megatonnes of carbon-dioxide equivalent worth of emissions in 2019 (Government of Canada 2021). Alberta's electricity emissions are expected to continue to decline as coal power plants transition to using natural gas as fuel. The change is expected to be complete by 2023, when the last coal plants are converted, well ahead of the 2030 deadline (Healing 2020). But to further decarbonize, Alberta's heavy reliance on natural gas generation will need to be replaced by lower- or zero-emitting energy sources.

Figure 1. Alberta’s electricity-sector emissions



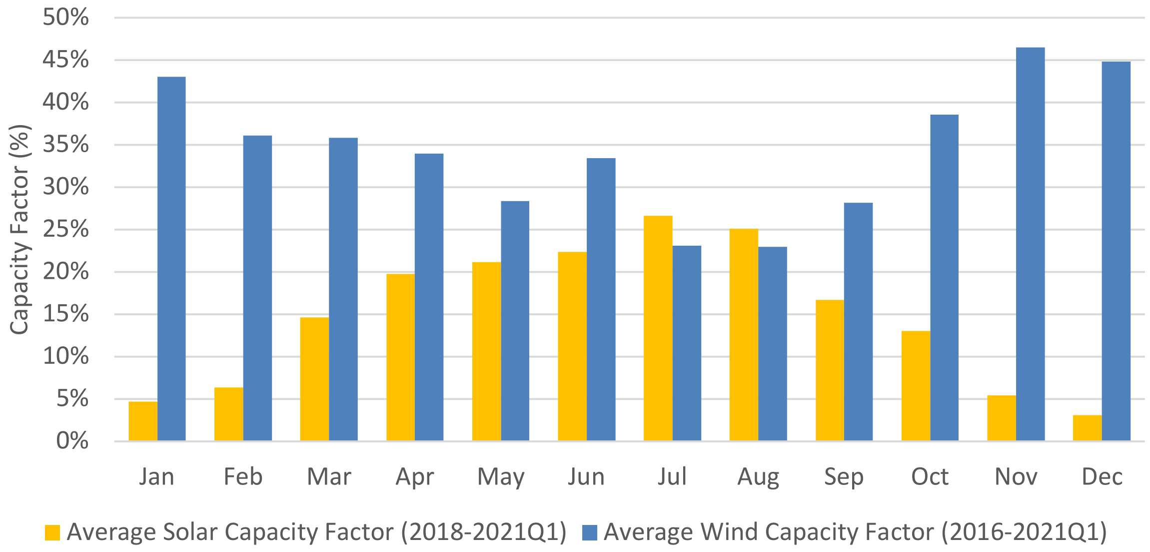
Source: Government of Canada, Canada's Official Greenhouse Gas Inventory (2021)

Currently, wind is the dominant renewable energy resource in Alberta, with an installed capacity of just over 2,000 megawatts. Wind’s growth has been a function of government policies (both in Alberta and outside the province, with early projects benefiting from California-based incentive programs specifically and global innovation support in general) and rapidly declining costs making the private economics of wind generation competitive. Wind and solar continue to be a popular solution, with just over 5,200 megawatts of wind and over 4,300 megawatts of solar capacity in the planning queue, as declared in the June AESO Connection Project List (AESO 2021c). However, capacity values do not tell the entire story. As VRE resources, wind and solar will fluctuate in the actual amount of energy generated from their rated capacity. Annual capacity factors are roughly 15 per cent for solar in the province, and 30 to 45 per cent for wind power, depending on location and wind turbine technology (with newer projects towards the upper end and older ones nearer the bottom of that range). Furthermore, not all of these project proposals will get built, as their connection to the Alberta grid will be dependent on availability of project financing, transmission capacity becoming available, and favourable market signals as projects move toward their desired construction date.

2.2 WIND AND SOLAR-GENERATION PROFILES

Alberta’s current wind fleet has a capacity factor of roughly 31 to 35 per cent (AESO 2020, 23) meaning it generates 31 to 35 per cent of its maximum rated capability over an average year. Newer projects with newer technology (with taller turbines and longer blades) are projected to reach above 40 per cent. This generation, however, varies widely from month to month and hour to hour. Wind has a seasonal trend, with higher wind generation occurring in the winter than in the summer (Figure 2). On a daily level, wind generation in Alberta also tends towards evening hours, when the temperature gradients are at their highest.

Figure 2. Alberta average wind and solar capacity factors



Data source: AESO 2021b.

Alberta's solar generation operates at an annual 15 per cent capacity factor, with the monthly production reaching up to 26 per cent, depending on panel technology. While lower than solar-rich locations in the U.S. southwest, Alberta (along with southern Saskatchewan) has the highest levels of solar intensity in Canada. Solar's seasonal profile, unsurprisingly, tends towards higher capacity factors in the summer months in Alberta on account of its northern latitude (see Figure 2). Solar is also more consistent on a day-to-day basis than its wind counterpart, with some variation based on cloud cover. Solar's main challenge vis-à-vis electric load is that supply falls just as evening peak demand hours arrive. This creates a large evening ramping challenge for grid operators to meet the large swings in net load (CAISO 2016).

Collectively, wind and solar are reasonable complements in Alberta, on account of their different seasonal profiles. In fact, southern Alberta and Saskatchewan are some of the few areas in the world where either the sun is shining or the wind is blowing at least 75 per cent of the time (Fasihi et al. 2016)

2.3 THE RENEWABLE CHALLENGE

The challenge with VRE remains its inability to match supply with demand. Relying on more wind and solar will replace fossil-fueled generation during times of renewable generation, providing a benefit to electricity users in the form of reduced fuel costs and emissions displacement, but will require other complementary features in the electricity system to maintain reliability at all times.

One option is to build larger electric interconnection capacity between provinces. Doing so takes advantage of the relative strengths of neighbouring provinces. Alberta's cost advantage in cheap but variable wind and solar energy could be well complemented by B.C.'s flexibility and storage from its hydroelectric system. Together, Alberta could provide bulk raw energy while B.C. provides firming capacity. However, such a solution faces many obstacles: from local opposition to linear infrastructure, Indigenous land rights, differences in electricity market and regulatory structures between the provinces, and political challenges reflecting the positions of winners and losers from trade. In short, transmission is an elegant and valuable solution, but it would likely require significant co-ordination and co-operation between the two provinces to overcome its many obstacles.

Another much-discussed option is to increase energy storage capacity, effectively shifting electricity from periods of excess to periods of need. This has begun in Alberta, with the installation of a few battery storage facilities with a cumulative 50 megawatts of output. However, the bulk of battery investment to date is in relatively short-duration batteries with a capacity of 64.3 megawatt-hours, which are able to manage small sub-hourly swings, but not week-long periods of low or no wind, and certainly not large seasonal swings (AUC 2019, 2020a, 2020b, 2020d). To manage prolonged periods of low wind associated with extreme cold events in Alberta's winters, or to deal with the seasonal variation in renewable generation, longer-duration storage will be required. Longer-duration storage projects, such as the pumped hydro reservoirs at Brazeau or at Canyon Creek, near Hinton, Alta., could provide significant long-term storage to complement renewables. Canyon Creek is slated to come online with a 75-megawatt discharge capability and a reservoir lasting over 37 hours (AUC 2018).

Hydrogen presents as an alternative solution to the VRE challenge. The potential opportunities exist on both sides of the market. First, the production of hydrogen via electrolyzers (converting water into its hydrogen and oxygen elements) can be a flexible consumer of renewable electricity when renewable generation is abundant. This helps to manage periods of excess generation. Second, the resulting hydrogen can itself be the fuel used in Alberta's combustion turbines in place of natural gas to generate electricity when renewable generation is scarce. One-way alkaline and proton exchange membrane electrolyzers are already commercial and costs are falling rapidly, while prototype two-way solid-oxide fuel cells already exist that can perform both as fuel cells and electrolyzers (Dowling et al. 2020).

2.4 HYDROGEN AS A GENERATION FUEL SOURCE

Hydrogen does not produce any carbon-dioxide emissions when used to generate electricity; water is the only resulting product when hydrogen is reacted with oxygen, either by combustion or through a catalyst in a fuel cell. This is important in a stationary application, because after hydrogen is used for electricity production, it converts back to water, and thus can be recycled for hydrogen production again through electrolysis. Hydrogen can thus complement wind and solar generation by being a firming fuel to be produced in times of energy abundance and transformed back into electricity in times of scarcity.

Hydrogen also has an advantage in energy-storage duration compared to current battery technologies. Hydrogen storage typically comes in two forms: in scalable above- or below-ground pressure vessels, or in underground formations, such as salt caverns (IEA 2019; Mallapragada et al. 2020). Salt-cavern storage, where available, would likely be very inexpensive and capacious, while pressure vessels would likely cost $0.15 to $0.25 per kilogram for daily fill-and-empty use, with the cost per kilogram rising (beyond this range) or falling with reduced or increased cycling. These storage solutions could provide weeks or even months of storage capacity relative to the hours that current battery technologies can provide. For example, electricity generation from the summer months could be transformed into hydrogen and stored for later use in the winter. Therefore, producing hydrogen through electrolysis could provide a seasonal storage mechanism to complement VRE sources.

2.5 ALBERTA'S STEAM AND COMBUSTION TURBINES

Alberta is well-positioned to repurpose its existing steam and combustion turbine infrastructure to utilize hydrogen fuel. This is because hydrogen has similar combustion qualities to methane when carefully mixed to match energy delivery in combustors, and so is able to be used as a complementary or replacement fuel in Alberta's current combustion- and steam-turbine infrastructure. Doing so limits the number of greenfield projects required in Alberta's decarbonization pathway, lowering overall costs, as much of the existing electric infrastructure (including powerhouse components and transmission equipment) can be repurposed.

Combustion turbines fueled by methane, whether in simple-cycle or combined-cycle configuration, are the most common type of generator in the Alberta electricity market. Many of these turbines can already use hydrogen as part of their fuel mix and can further undergo modifications to use higher concentrations of hydrogen (General Electric n.d.). General Electric, the dominant manufacturer of combustion turbines installed in Alberta, has a historical track record of using hydrogen in its turbines (Rahm et al. 2009, 7) and has successfully piloted turbines using 90-per-cent hydrogen fuel. There are several projects in the U.S. to transition natural gas units to use hydrogen, including the Sheldon Power Station in Nebraska and the Intermountain Power Plant in Utah. Worldwide, many pilot and full-scale transition projects are occurring (Wagman 2017; Patel 2020).

Box 1: Intermountain Power Plant

Intermountain is an 1,800-megawatt coal-fired power plant located in Delta, Utah. It was commissioned in 1986, with two steam turbines fueled by coal. In 2012, the Intermountain Power Agency looked to convert the two coal boilers to use natural gas in order to reduce emissions. This was driven by the SB 1368 environmental performance standard enacted in 2006, requiring all baseload generation to meet emissions intensity equal to a combined-cycle natural gas plant (Cassell 2012).

Instead, in 2019, Intermountain decided to replace the existing coal/steam boilers with two new Mitsubishi M501JAC combustion turbines, for a total of 840 megawatts. These units are being designed to run with a fuel mixture consisting of 30-per-cent renewable hydrogen along with 70-per-cent natural gas when construction is complete in 2025. As time goes on, the plant will be retrofitted during planned maintenance cycles to use 100-per-cent hydrogen by 2045 (IPA n.d.).

The Intermountain project is unique because it sits on a salt cavern that will be used to store hydrogen produced from electrolysis powered by local VRE sources. Salt caverns can be hollowed to form custom volume storage that will not react with hydrogen and enjoys a significant cost advantage over above-ground hydrogen storage for long discharge-duration options (IEA 2019). Such cavern systems can store vast amounts of hydrogen, holding fuel for upwards of 150,000 megawatt-hours of energy. In order to produce this amount of energy with lithium-ion batteries, it would take up to 40,000 shipping containers filled with grid-scale-sized batteries (Compton 2020).

Lessons from the Intermountain project can be readily applied in Canada, especially in Alberta, with its current fossil-thermal-dominated electricity system, large variable renewable resources, and appropriately located salt-cavern geology in the Fort Saskatchewan area, near chemical plants, which can also make use of electrolyzed hydrogen and oxygen.

Alberta also has several steam turbines, currently or previously fueled by coal, that could be converted to use hydrogen or hydrogen-based fuels, such as ammonia, in their boilers. At this point, all coal plants have either started the conversion process to replace coal with natural gas, have decided to shut down, or have converted to a combined-cycle unit by repowering with a combustion turbine in sequence with the existing steam turbine.[1] Conversion to natural gas appears to be the favoured option, with Capital Power, TransAlta Corp. and Heartland Generation Ltd. announcing their intent to convert their existing facilities to incorporate methane either through a coal-to-gas boiler conversion or by repowering as a combined-cycle gas turbine (Capital Power n.d.; TransAlta n.d.; AUC 2020c). If the firms are already going through the conversion process to natural gas turbines, the option to include hydrogen in the fuel mixture could also be built into these turbines (along with space and access for

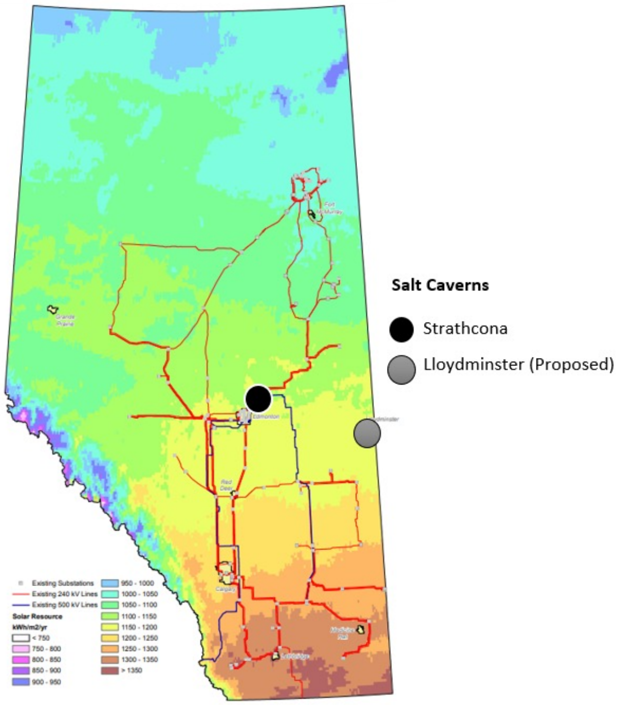
[1] See, for example, TransAlta, "Repowering Projects" (https://www.transalta.com/plants-operation/repowered-combined-cycle-units/) for an example of repowering coal plants to combined-cycle natural gas.

hydrogen storage), potentially further reducing the emissions from these power plants. The alternative of just shutting down the existing facilities leaves a large amount of existing transmission capability underutilized. This could be of even larger importance in Ontario, because much of the transmission system is webbed around the coal plants that were shut down in the 2007–14 period.

There is also another location aspect to consider. Coal power plants were located next to coal mines to minimize transportation costs. Not all coal power plant locations may be able to get a steady supply of hydrogen unless significant transmission capability is built or electrolyzers are located in close proximity to such facilities. This suggests that greenfield hydrogen-fired electricity generation turbines may benefit most from locating near hydrogen supply or storage assets, whether it be a hydrogen transmission system, a steam-methane reformer with carbon capture and storage, salt-cavern seasonal storage, or an integrated hybrid site, like Intermountain, consisting of variable energy resources, an electrolyzer and a generator turbine. This hybrid configuration could benefit from a number of revenue streams, including electricity from variable generation (at a discount, if VRE sources continue to grow and depress pool prices); grid-reliability service payments from the electrolyzer; electricity from combustion turbines and eventually fuel cells; and an opportunity to sell hydrogen and oxygen gases as high-value chemical feedstocks (Preston et al. 2020). Alberta is already eyeing salt caverns as a means to store crude oil and compressed air, but this capacity could instead be used for hydrogen storage.

The Strathcona Salt Cavern (see Figure 3, below) is located near the backbone (240-kilovolt) alternating-current lines of the Alberta grid, and the high-voltage direct current Western Alberta Transmission Line and Eastern Alberta Transmission Line (of 500 kilovolts each) meet near the cavern, allowing transmission of renewable-sourced energy to and from the cavern site from southern Alberta. A facility like Intermountain over the Strathcona Salt Cavern, running initially on a methane and hydrogen mix, then 100 per cent hydrogen, or two-way solid-oxide fuel cells, could create multiple firm renewable power benefits (Jenkins et al. 2018; Sepulveda et al. 2018). Electricity could be purchased when cheap ($0.01 to $0.03 per kilowatt-hour) to produce hydrogen, which would be stored in the cavern, helping stabilize electricity prices during surplus. It could then be converted back to electricity at 40-to-50-per-cent efficiency in times of electricity scarcity, with likely prices of $0.075 to $0.15 per kilowatt-hour. The location would also be ideal for short-term response, voltage regulation, and general grid-reliability services served from electrolyzers or co-sited batteries (Allidières et al. 2019, 9699).

Figure 3. Location of Strathcona Salt Cavern, proposed Lloydminster Salt Cavern and main Alberta transmission line



Source: AESO 2019; Adapted by Authors

3. THE ECONOMICS OF NATURAL GAS AND HYDROGEN FOR POWER GENERATION IN ALBERTA

As Alberta moves towards a higher share of VRE sources to power its electrical grid, having fast-reacting low-carbon generation will become even more crucial to balancing the grid and maintaining reliability. Peaking supply options can provide such services; the question is, *at what point will using hydrogen be preferable to natural gas?*

To answer this question, we construct a production-cost model that estimates the break-even price point for hydrogen to become preferable to natural gas for power generation. The model incorporates marginal costs of electricity generation based on input fuel costs and carbon costs incurred by natural gas. As the carbon price increases over time, the cost of using natural gas for generation rises, raising the break-even price (in terms of cost per kilogram for hydrogen production) at which hydrogen becomes the economical choice.

After identifying break-even prices for carbon prices at both $50 and $170 per tonne, we then calculate the cost of producing hydrogen from natural gas via steam-methane reforming (SMR) using the latest model from the U.S. National Renewable Energy Laboratory. We further modelled hydrogen production costs from electrolysis assuming a 70 per cent capacity factor, operational costs, three distinct capital costs and varying electricity costs from the 2019 IEA Future of Hydrogen report. This exercise gives a sense of the relative economics of different production methods for hydrogen vis-à-vis one another and natural gas for power production.

We then further enhance the model to incorporate details regarding carbon-pricing regimes. In Section 3.1, we include a strict carbon price on emissions in the production and generation side. In Section 3.2, we incorporate output-based allocations (OBAs) specific to Alberta's carbon policy. The contrast between excluding OBAs and including them demonstrates the dramatic impact OBAs have on price incentives for hydrogen in Alberta. Finally, we compare the production costs and carbon-price impacts in each scenario to the break-even points, to find the point that hydrogen becomes preferable to natural gas for power generation for carbon prices between $50 and $170 per tonne.

3.1 HYDROGEN VERSUS NATURAL GAS WITH CARBON POLICY AND NO OUTPUT-BASED ALLOCATIONS

Based on our model and the research that informs it, we conclude the price of hydrogen without any OBAs would need to be as low as $0.70 per kilogram today to generate power at the same cost as from natural gas in a simple-cycle turbine, given 2022 carbon prices and a natural gas price of $3.00 per gigajoule. In this scenario with no OBA subsidies, carbon costs represent roughly half of the marginal cost of generating power from a simple-cycle plant running off natural gas. As the carbon price rises, the break-even price where hydrogen starts to become more economical than natural gas also rises. By 2030, with a projected carbon price of $170 per tonne, hydrogen costs need only be $1.50 per kilogram, rather than $0.70 per kilogram, to beat $3-per-gigajoule natural gas, improving the prospects for hydrogen (Figure 4).

Figure 4. Break-even prices of hydrogen versus natural gas ($/MWh)

Figure 5 shows the improving prospects for hydrogen, as shown by the larger yellow-shaded region, which indicates hydrogen production costs and natural gas price combinations where hydrogen is more economical than natural gas for power production.

Figure 5. Break-even prices of hydrogen for a simple-cycle gas turbine in 2022 to 2030 without output-based allocations compared to estimated electrolysis production costs with a 70% capacity factor and $37/MWh electricity price, and estimated methane-reforming costs

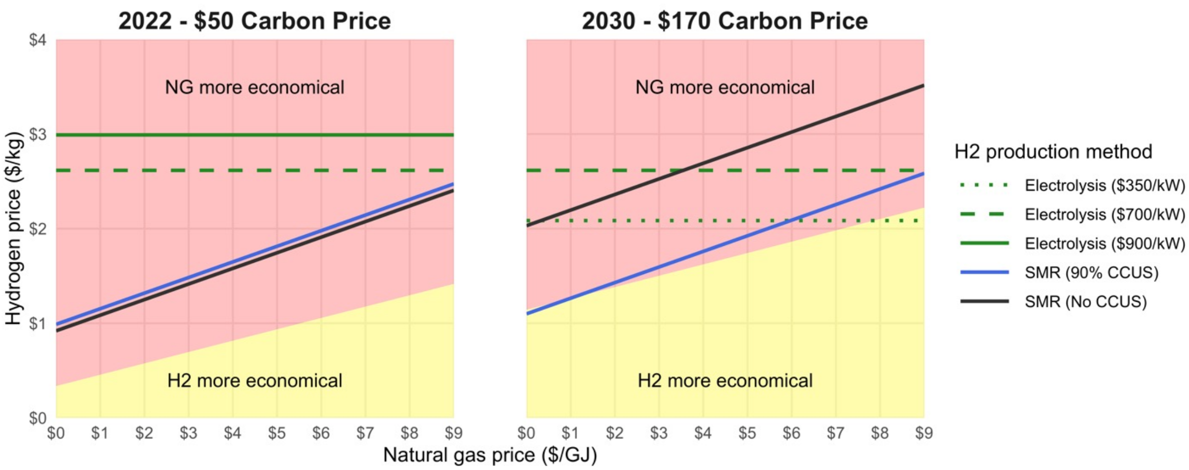


Figure 5 includes estimates of production costs for hydrogen from methane reforming and electrolysis, at varying degrees of carbon capture and storage (CCS) costs and electrolyzer capital costs, respectively. At a $50-per-tonne carbon price (left panel), the cost of 90 per cent CCS is roughly equivalent to the carbon costs faced by unsequestered "grey" hydrogen (produced from steam reforming). At $170 per tonne (right panel), the advantages of "blue" hydrogen (produced by steam reforming with carbon capture) over "grey" hydrogen become clear, even at 90-per-cent CCS. For "green" hydrogen (made from renewable energy), the production costs are very sensitive to assumptions around capital costs of the electrolyzers. Green-hydrogen production remains more expensive than 90 per cent CCS blue hydrogen, even at a carbon price of $170 per tonne, in most situations. Even with aggressive reductions in the capital costs of the electrolyzers down to US$350 per kilowatt by 2030, gas prices must still exceed $6 per gigajoule for electrolysis to be favoured over steam reformation. Further information on key assumptions is included in the appendix.

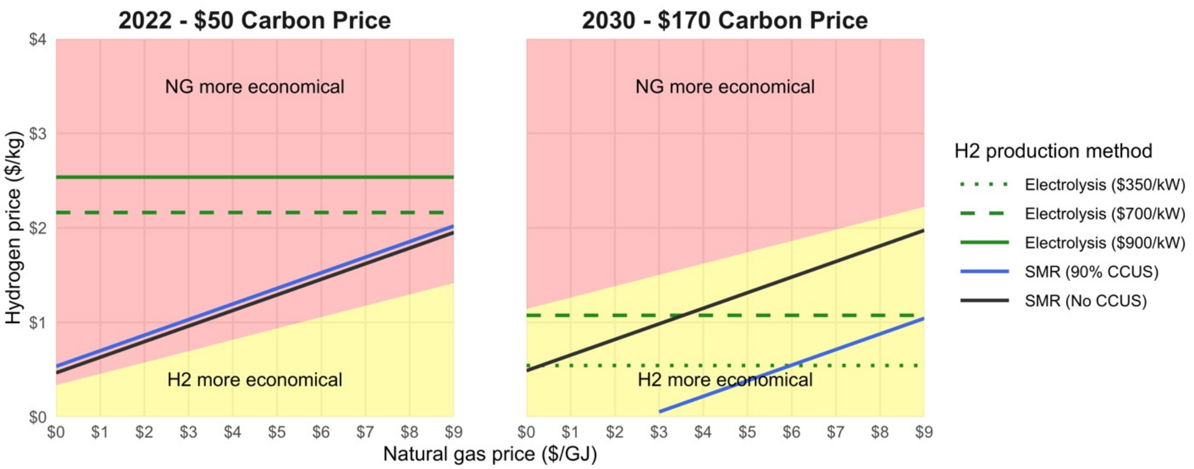
Ultimately, however, even at a $170-per-tonne carbon price, the prospects for hydrogen in the power sector remain bleak absent either lower electricity prices and/or cost reductions in electrolyzer and SMR/CCS technology. This suggests that, without supportive policies, hydrogen may only become the cost-minimizing fuel for electricity generators with either significant reductions in electrolyzer capital costs and/or CCS technology, even lower renewable-electricity prices, or greater than $170-per-tonne carbon prices. However, the story does not end there, as Canada's (and Alberta's) large-emitter carbon-pricing policy includes another component, OBAs, which play an important role in the economics of hydrogen in the power sector.

3.2 HYDROGEN VERSUS NATURAL GAS WITH CARBON PRICING AND OUTPUT-BASED ALLOCATIONS

While the above scenario incorporates Canada's stated policy of a carbon price of $170 per tonne by 2030, it does not include the OBA component of the large-emitter policy. OBAs set a benchmark in terms of tonnes of emissions per unit of output, above which firms pay for emissions, and below which firms receive credits. Alberta has an OBA scheme (known as TIER, or Technology Innovation and Emission Reduction regulation) for both electricity *and* hydrogen production. For electricity, the benchmark is set at 0.37 tonnes of carbon-dioxide equivalent per megawatt-hour, and for hydrogen production the benchmark is 9.068 tonnes of carbon-dioxide equivalent per tonne of hydrogen. These allocations provide subsidies that drastically reduce the realized production costs of clean hydrogen, shifting the relative economics as compared to the no-OBA scenario in Figure 5, making it the preferable fuel even before 2030.

Figure 6 illustrates the effect of Alberta's OBA system on the relative economics of power through hydrogen versus natural gas. The OBA subsidies applied to hydrogen substantially improve its economics in power generation. **At a carbon price of $170 per tonne, all forms of hydrogen-based power production dominate natural gas.** This comes about from an effective "pancaking" of policy — hydrogen-based power production receives OBAs in two sectors: first during hydrogen production, and second during zero-emission power generation. Perversely, such a system provides subsidies for steam reforming without CCS, making it the preferable alternative to just burning natural gas, which is counter to the end objective; as noted in our companion paper (Bataille et. al., 2021), such "grey" hydrogen emissions are actually higher than just using natural gas. Key assumptions to this model are further outlined in the associated appendix.

Figure 6. Break-even prices of hydrogen for a simple-cycle gas turbine in 2022 to 2030 with output-based allocations compared to estimated electrolysis production costs with a 70% capacity factor and $37/MWh electricity price, and estimated methane-reforming costs



Overall, OBAs alter the playing field in favour of hydrogen, such that with a carbon price of $170 per tonne, hydrogen produced through methane reforming with 90 per cent CCS or electrolysis is preferable to using natural gas in a simple-cycle electricity generator. As a result, hydrogen would displace natural gas from the power grid.

As it stands, natural gas still enjoys a steep discount compared to current hydrogen costs, but the future of Alberta's carbon policy will largely determine whether or not hydrogen becomes the preferred fuel prior to 2030. However, there are already new competitive technologies being proposed in Alberta that promise further cost reductions below that of current methane-reforming levels that may further encourage a quicker transition to hydrogen (ERA 2020). Is important to note that hydrogen produced through SMR or autothermal reforming provides value through a consistent, relatively cheap source of hydrogen to help with the initial adoption of hydrogen fuel use in the industry. As electrolysis costs fall due to economies of scale and technological innovation, recycling the water by-products from combusting hydrogen will help build a renewable and reliable system that doesn't require gas-drilling operations, which are subject to upstream fugitive emissions.

4. DISCUSSION AND CONCLUSION

Alberta faces a challenging journey in its transition to net-zero in the electricity industry because of its reliance of existing fossil fuels, but hydrogen is an opportunity to bridge today's system to tomorrow's net-zero fuels and technologies. A key policy element enabling hydrogen will be the current carbon-based allocation incentives under TIER. Our model determines that the rising carbon prices to 2030, along with Alberta's OBAs for hydrogen and electricity, offset a large portion of the overall costs to create hydrogen, and provide sufficient incentives to use hydrogen rather than natural gas as a preferred fuel closer to 2030.

The crucial assumption is that the current TIER output-based allocations are not set to change or have built-in mechanisms to reduce the allocation over time. As industry innovates and adopts carbon-capture methods for hydrogen production, as we have seen recently with Air Products Inc., ATCO Ltd. and Suncor Energy Inc., the government will need to consider at what point the OBA for hydrogen and electricity need to change. For example, a 95 per cent carbon-capture rate on the current 9.068 total carbon dioxide-to-total hydrogen benchmark with a $170 carbon price would result in a $1,464 subsidy per tonne of hydrogen produced. Maintaining the OBAs at current levels may not be sustainable. In Alberta, such subsidies are funded by firms paying for emissions that exceed the OBA benchmarks, and companies moving to lower-carbon methods of production would have the effect of slashing the amount of money going into the fund to pay for such subsidies. Alberta should consider how transparency on any future allocation changes may positively impact hydrogen investment and lower the overall risk of such investment in the province.

While there are many unknowns attached to Canada's journey to net-zero, and hard choices about infrastructure spending will need to be made, there are a couple of no-regrets actions that will increase future options by preparing today's infrastructure for tomorrow's energy systems (CICC 2021).

1. All new combustion turbines for electricity generation should be able to run hydrogen with minimal or no retrofitting. This is not as onerous as it sounds, because much of the fleet already can run hydrogen, and it doesn't interfere with using methane.

2. Salt caverns will be highly sought after for seasonal hydrogen storage. It is important that they are not ruined nor allocated for natural gas storage in any way that precludes using them for hydrogen storage. Given they are mostly under provincially governed Crown lands, and the subsurface rights belong to the Crown, it may be appropriate to bring their governance into the electricity- and gas-transmission system. Relatedly, the position and condition of salt caverns across Canada should be mapped and assessed with respect to the transmission system and potential renewable-electricity resources.

Ultimately, one of the most valuable roles for hydrogen will be in assisting the decarbonization of the power sector. As the share of the electrical grid made up of renewable power increases, hydrogen can play an essential role in both absorbing excess generation during periods of wind and solar abundance for electrolysis, and generating firm, reliable, power in hydrogen-capable gas turbines. The combination of larger shares of renewables supported by complementary hydrogen infrastructure offers a pathway to decarbonizing power grids that have historically been more reliant on fossil fuels for electricity generation, such as those in Alberta, Saskatchewan, and parts of the Maritimes.

APPENDIX

Key Assumptions for Figure 5	Value	Units
Natural Gas Emissions	56	gCO_2e/MJ
SMR Emissions for H_2	77.3	gCO_2e/MJ
SCGT Heat Rate	9.127	MJ / kWh
TIER Output-Based Allocation — Electricity	0	tCO_2e/MWh
TIER Output-Based Allocation — Hydrogen	0	tCO_2e/kgH_2
SMR Base Production Cost	0.457	$\$/kgH_2$
SMR 90% CCS Cost	0.485	$\$/kgH_2$
SMR Natural Gas usage	0.165	GJ/kgH_2
SMR Emissions for H_2	77.3	gCO_2e/MJ
Electrolysis Electricity Usage	0.0486	MWh/kgH_2
Electrolysis Electricity Cost	37	$/MWh

Key Assumptions for Figure 6	Value	Units
Natural Gas Emissions	56	gCO_2e/MJ
SMR Emissions for H_2	77.3	gCO_2e/MJ
SCGT Heat Rate	9.127	MJ/kWh
TIER Output-Based Allocation — Electricity	0.37	tCO_2e/MWh
TIER Output-Based Allocation — Hydrogen	9.068	tCO_2e/kgH_2
SMR Base Production Cost	0.457	$\$/kgH_2$
SMR 90% CCS Cost	0.485	$\$/kgH_2$
SMR Natural Gas Usage	0.165	$GJ\ NG/kgH_2$
SMR Emissions for H_2 Production	77.3	gCO_2e/MJ
Electrolysis Electricity Usage	0.0486	MWh/kgH_2
Electrolysis Electricity Cost	37	$/MWh

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