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A Zero-Emission Canadian Electricity System by 2035

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Foreword

In jurisdictions around the world, clean-electricity standards and carbon pricing have been used to reduce emissions from the electricity grid and to favour accelerated investment in renewables and other zero-emissions electricity generation.

Fuel switching from dirty fossil fuels to clean electricity is an essential part of any serious climate policy. The International Energy Agency's Net Zero by 2050 report offered a detailed pathway to transition to a net-zero energy system by 2050. It shows that current investments in renewable energy are lagging far behind what is required to achieve a climate-compatible global energy system, one that will also avoid the many health impacts of burning fossil fuels.

In fall 2020, the federal government announced that the carbon price would increase annually until it reached $170/tonne in 2030, a measure that is anticipated to support further decarbonization of Canada's grid and increased electrification across the economy. In addition, in Canada's enhanced climate plan, "A Healthy Environment and a Healthy Economy," the government committed to "explore the role of a clean electricity performance standard to ensure electricity generation achieves net-zero emissions before 2050." While Canada has a relatively clean electricity grid by global standards, emissions need to be brought rapidly to zero even as generation expands markedly.

The David Suzuki Foundation, working in collaboration with the Conservation Council of New Brunswick, the Ecology Action Centre and the Pembina Institute, commissioned this report from Mark Jaccard and Brad Griffin, two respected energy economists and policy experts, to set out how a national clean-electricity standard or intensified carbon pricing could be designed. They were tasked to focus on zero-emission policies that the federal government has the authority to implement in support of national GHG targets. This was no easy task, however, given that the electricity sector is primarily a matter of provincial jurisdiction, environment is a shared jurisdiction and Canadian courts have clearly shown a preference for laws that are consistent with the "co-operative federalism" baked into Canada's Constitution. Furthermore, some provinces have large reservoirs and hydroelectric generation stations that can serve as giant batteries to back up renewable resources, while others rely on high-emitting fossil generation, implying that costs across the country to rein in emissions will vary widely.

Jaccard and Griffin offer detailed provisions for a clean-electricity standard and intensified carbon pricing and demonstrate how either of these policies or the two combined would enable Canada to achieve a net-zero GHG emissions electricity system by 2035 and sustain it at net-zero while the total system doubles in size by 2050 as fossil fuels are switched out for clean electricity. They model two different scenarios, considering governments may have other policy priorities and the social acceptability of different generation technologies can evolve over time.

To be clear, the David Suzuki Foundation is not advocating that the exact configuration of new generation capacity shown in either of the two scenarios be built. The primary purpose of this study is to set out how an effective clean-electricity standard could be designed and then to demonstrate how it would affect existing generation and investments in new generation. Indeed, while both scenarios show dramatic growth in renewable generation, one of the scenarios posits that in a couple of regions, there will be continued though reduced reliance on fossil generation, and it assumes construction of another large hydro project. However, fossil generation projects are only allowed where they incorporate carbon capture and storage and other measures to zero out emissions. There are reasons to be skeptical that this would be the best approach from economic and environmental points of view, especially as CCS has never been deployed at this scale before, and two recent large hydro projects have seen dizzying cost overruns. Furthermore, there is skepticism among many that CCS would merely serve to provide a rationale for continued expansion of fossil gas extraction. The second scenario forgoes even a modest reliance on fossil fuels with carbon capture and storage and assumes no new large hydro projects proceed before 2050, resulting in increased deployment of wind, solar and other renewables, plus investment in storage to address the variability of these resources.

The actual grid of the future will be the result of many factors. In particular, Indigenous land and title rights must be respected. New clean energy projects require Indigenous consent and participation. Host Indigenous communities are rightfully insisting on a significant ownership stake and in some cases, they own projects outright. Investments in expanding clean electricity must protect biodiversity objectives, be designed with local communities and deliver broad benefits. However, this report necessarily sets aside all these issues. The authors were given a specific mandate and a tight timeline, so it is laser-focused on designing federal policy to achieve a zero-emission Canadian electricity system. Unless we zero out the emissions from Canada's grid — all while expanding generation capacity — Canada's climate targets will not be achieved This report is one contribution toward careful deliberation around the design of federal policy to ensure a net-zero emission national electricity system.

Tom Green
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Executive summary[1]

In this report, we explain how Canada can achieve a net-zero greenhouse gas emissions electricity system by 2035 and sustain it at net-zero as the total system doubles by 2050. This being a Canada-wide objective, we focus on zero-emission policies that the federal government could implement under its authority to set national GHG targets and implement policies of national reach to achieve them. Our federal policy focus is complicated, however, by the fact that the electricity sector is primarily under provincial jurisdiction, environment is a shared jurisdiction and Canadian courts support the "co-operative federalism" spirit of Canada's Constitution.

While much of Canada is currently blessed with low-emission electricity from hydro and nuclear power — along with modest contributions from wind, biomass and solar power — some provinces still rely on GHG-emitting coal and natural gas power plants. This contrast in the carbon intensity of provincial electricity systems means that the costs of initially achieving net-zero electricity systems differ between provinces. We therefore propose to reduce divergent cost impacts of federal GHG policy by allowing those provinces with higher carbon-intensity electricity to transition more gradually. Thus, our proposed policies set a net-zero deadline of 2030 for B.C., Manitoba, Quebec, Newfoundland and Labrador and P.E.I., but of 2035 for Alberta, Saskatchewan, Ontario, New Brunswick and Nova Scotia.

Transitioning Canada's current electricity system to net-zero is a big challenge. An even bigger challenge is to maintain that net-zero character while the system doubles in output over the next three decades, as electricity consumption replaces the use of coal, oil products and natural gas in transportation, buildings and industries. One constraint is that large hydro and nuclear power, the mainstays of Canada's current electricity system, are unlikely to receive the same social and political licence for major expansion as in the 1960s to 1980s. Another constraint is that while carbon capture and storage (CCS) is an option for reducing 85 to 90 per cent of emissions from current and future coal and natural gas plants, this technology might also be seen as unacceptable in some locations and it does not by itself achieve net-zero emissions.

Fortunately, Canada's geography provides favourable opportunities to develop wind and solar throughout the country, as well as region-specific biomass, small hydro and some geothermal. And while the electricity output of solar, wind and small hydro plants is variable (hence non-dispatchable), these sources can be integrated with energy storage as well as with incentives to adjust the timing of electricity demand (load shifting). Ideally, grid-connected, non-dispatchable generators anywhere in Canada would also benefit from the enormous energy storage of

[1] Mark Jaccard is Distinguished Professor and Director of the School of Resource and Environmental Management and Brad Griffin is Director of the Canadian Energy and Emissions Date Centre, both at Simon Fraser University.

Canada's existing hydropower reservoirs, but nationwide utilization of this resource requires expanded grid interconnection between provincial electricity systems.

Canada's Supreme Court has affirmed the Canadian government's right to set national GHG emissions targets and implement carbon pricing and emissions-intensity regulations as part of its nationwide effort to achieve these targets. But the federal government does not have a free hand, especially in the electricity sector. Electricity investment and dispatch decisions in Canada are made by private and public corporations (and some municipal utilities) in a complex policy, regulatory and ownership landscape that is dominated by provincial governments. Most provinces have provincial Crown corporations involved to varying degrees in generation, transmission, distribution and system operation. All provinces have an electricity regulator. And all provinces have policies to reduce GHG emissions from electricity generation, although these differ significantly between provinces and collectively neither achieves Canada's 2030 Paris GHG commitment nor puts it on a trajectory to achieve its 2050 net-zero commitment.

It is in this context that the federal government's GHG electricity policies have been associated with the terms "equivalency agreement" and "backstop." Where a province has GHG-reducing policies at stringencies close to those of the federal government, the two governments may negotiate an equivalency agreement that gives precedence to the provincial policy. However, where a province's GHG policies are deemed insufficiently stringent, the federal government may opt to apply its carbon price or regulatory standard as a backstop in that province.

In the case of electricity GHG emissions, two federal policies are key. First, the federal government has an emissions performance standard under the Canadian Environmental Protection Act that sets maximum emission limits of CO_2/kWh for electricity generation plants. The latest version of this standard will force the closure of coal-fired power plants by 2030 if they have not installed effective CCS, but it does not prevent the ongoing operation of existing natural gas plants without CCS, nor of coal plants converted to natural gas without CCS.

Second, the federal government has a price on carbon it can apply to electricity plants via its industrial output-based pricing system (OBPS) under the Greenhouse Gas Pollution Pricing Act. As applied to electricity generators, the OBPS sets benchmark emission intensity standards for each category of generator and charges the carbon price only on emissions exceeding the standard. This incentivizes some emissions reductions without causing significant increases in electricity rates in the provinces with coal and natural gas generators, because only a percentage of emissions are charged the carbon price. However, its benchmark standards allow ongoing GHG emissions beyond 2030 from existing natural gas plants, as well as from coal plants that have been retrofitted with CCS or converted to natural gas.

Given the necessity of a Canadian shift to zero-emission electricity, we propose that the federal government adjust the stringencies of these two policies to ensure that electricity generation in every Canadian province is net-zero by 2035 at the latest, and remains that way as the system grows to 2050. Specifically, the carbon intensity standard should fall to net-zero CO_2/kWh by 2030 in provinces dominated by hydro, nuclear and wind, and by 2035 in provinces currently relying on some coal and natural gas. And the OBPS, as applied to all electricity generators, should adjust the benchmark standards until 100 per cent of electricity-related GHG emissions are charged the rising carbon price that is currently applied to fuels, albeit again with different

2030 and 2035 deadlines depending on the province. This increase in coverage would occur as the carbon price rises on its announced path to \$170/tCO_2 in 2030 and then continues rising to \$300/tCO_2 and perhaps higher by 2050 if necessary to achieve the net-zero national target.

To illustrate the effect of these policy adjustments, we simulate two possible technology pathways for zero-emission electricity in all Canadian provinces by 2035. (In an appendix we also provide the outcome for northern territories.) In both pathways, we assume that provinces will not allow substantial expansion of large hydro and nuclear power, meaning that wind, solar and other renewables dominate generation growth. In both, we assume that the capacities of transmission grid interties between provinces will not be substantially increased, given past reluctance for expanded interdependence. And in both, we assume significant development of energy storage and load shifting to ensure reliable systems as the contribution of variable electricity from wind and solar increases.

The paths differ, however, in that in one we assume that some provinces will develop zero-emission options that are currently seen as acceptable by their governments. These include the substantial use of natural gas with CCS (and possibly bioenergy with CCS) in Alberta and Saskatchewan, and further development of large hydro in the Atlantic provinces (Gull Island) to take advantage of the new undersea transmission links. In the other path, we assume these developments don't occur, requiring instead even more wind, solar and other renewables, as well as the additional energy storage these require.

We estimate this second path as costlier. But that is based on current cost estimates of the various resource options. We note, however, that the eventual outcome could be reversed, especially given the recent experience of major cost overruns of two recent Canadian investments in large hydro (Muskrat Falls and Site C) and one electricity CCS project (the Boundary Dam coal plant).

We propose that the federal government continue to present its policies as backstops that can be superseded by equivalent provincial policies. However, the federal government must ensure that this co-operative approach does not result in reduced stringency by granting equivalency to provincial policies that are less likely to achieve a national zero-emission electricity system. To that end, we propose ongoing independent oversight of federal-provincial equivalency agreements by Canada's Net-Zero Advisory Body, using the assessment expertise of the Canadian Institute for Climate Choices.

We also propose that the federal government encourage multi-government equivalency agreements with two or more neighbouring provinces that wish to be treated as one entity for the purpose of electricity-sector GHG emissions. Dramatic increases in wind and solar over the next decades will require massive investments in energy storage, especially in provinces that lack large hydro reservoirs. These costs can be significantly lowered if federal policy promotes expanded grid interties between hydro reservoir–endowed provinces and their neighbours. However, given the primacy of provincial jurisdiction in electricity, this cost-saving interprovincial system co-ordination will only happen where provincial governments are willing. In this regard, the past decade has witnessed promising developments at least in the Atlantic provinces with the development of the Maritime Link transmission line.

As noted, our report is about federal policy to achieve a national objective, that being a zero-emission Canadian electricity system. Our report is thus silent on many other policy concerns of electricity system stakeholders. These unaddressed topics include centralized versus decentralized generation, economically efficient system operation, the pros and cons of public versus private ownership, financing capacity investments, electricity affordability, electric utility regulation, transition support for displaced workers, reliability of electricity generation and distribution as non-dispatchable renewables and electricity demand peaks increase, non-GHG environmental and social trade-offs of alternative zero-emission electricity options, cost-effective energy efficiency and load shifting, innovation and adoption in energy storage, reconciliation with Indigenous Peoples, and special challenges of zero-emission electricity in remote and northern communities. Many of these issues will be primarily addressed by provincial governments, each with their own priorities and preferred methods. However, the federal government must play a key role in supporting the net-zero transition in Indigenous and northern communities, given its clear constitutional responsibilities in these areas.

1 The policy challenge

1.1 Canada's zero-emission electricity options

All of Canada's main political parties agree that national greenhouse gas emissions should decrease rapidly toward net-zero by 2050, with an interim 2030 target ranging from 30 per cent to 60 per cent reduction from 2005 levels.[2] While aggressive gains in energy efficiency can contribute to this decrease, substitution from end-use combustion of fossil fuels to electricity will play a critical role in this transformation of the energy system. Electricity can replace oil products in transportation, natural gas and heating oil in buildings, and many uses of coal, oil products and natural gas in industry. But this growing use of electricity must coincide with a rapid shift to its zero-emission generation, perhaps even to negative-emission generation via the development of bioenergy with carbon capture and storage (BECCS).

Achieving and maintaining a zero-emission electricity system over the next three decades might not seem as great a challenge as for some countries because 80 per cent of electricity in Canada is already generated by zero-emissions sources. In 2019, hydropower provided 59 per cent of electricity, nuclear power 15 per cent, natural gas 10 per cent, coal seven per cent and other renewables like wind, solar and biomass seven per cent.[3] While coal has been significant in some provinces, this is changing. In 2004-2014, Ontario phased out all coal-fired power, which had provided 25 per cent of its electricity, and replaced it with natural gas, renewables and increased generation at its existing nuclear plants. Over the past decade, the other provinces with coal-fired power — Alberta, Saskatchewan, New Brunswick and Nova Scotia — have reduced their use of coal, replacing it mostly with natural gas and renewables, thus decreasing the average carbon intensity (CO_2/kWh) of their provincial electricity systems. Saskatchewan also added carbon capture and storage to one of the electricity generating units at its Boundary Dam power station, eliminating up to 90 per cent of CO_2 emissions from a 115 MW coal-fired power unit.[4]

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[2] Liberal Party of Canada. (2019). *Forward: A real plan for the middle class*. https://www2.liberal.ca/wp-content/uploads/sites/292/2019/09/Forward-A-real-plan-for-the-middle-class.pdf
Conservative Party of Canada. (2021). *Secure the Environment*: *The Conservative Plan to Combat Climate Change*. https://cpcassets.conservative.ca/wp-content/uploads/2021/04/15104504/24068610becf2561.pdf
New Democratic Party of Canada. (2019). *A New Deal for People: New Democrats' commitments to you.* https://action.ndp.ca/page/-/2019/Q2/2019-06-19_Commitments-Doc_EN.pdf
Green Party of Canada. (2019). *Honest. Ethical. Caring. Leadership. Election Platform 2019*. https://www.greenparty.ca/sites/default/files/platform_2019_web_update_oct_6.pdf
Bloc Québécois. (2019). *Le Québec, c'est nous: Plateforme politique du Bloc Québécois.* https://www2.blocQuebecois.org/wp-content/uploads/2019/10/Plateforme_Bloc2019_web-1.pdf

[3] Statistics Canada. Table 25-10-0019-01, Electricity from fuels, annual generation by electric utility thermal plants; Statistics Canada. Table 25-10-0020-01, Electric power, annual generation by class of producer.

[4] SaskPower. *Boundary Dam Carbon Capture Project.* https://www.saskpower.com/Our-Power-Future/Infrastructure-Projects/Carbon-Capture-and-Storage/Boundary-Dam-Carbon-Capture-Project. Accessed on 13 May 2021.

But while the existing low-emission system might suggest Canada has a comparative advantage for zero-GHG electricity, this will not necessarily continue to hold in coming decades. A key reason is that dramatic increases in electricity consumption will require massive new investments in electricity generation, with several independent studies suggest that achieving Canada's 2050 net-zero GHG target will increase domestic electricity consumption above today's 650 TWhs by between 60 and 250 per cent.[5] If GHG emissions were not a concern, Canada might partly meet this growing electricity demand from thermal plants using its plentiful resources of coal and natural gas. With North American prices of these two fossil fuels near all-time lows, where they are likely to remain, these are relatively low-cost options, especially because they are highly valued as "dispatchable" electricity sources (meaning that their output can be adjusted to match seasonal, daily and hourly fluctuations in electricity demand). Unless zero-emission options are cheaper and equally dispatchable, governments must implement policies that prevent or make prohibitively expensive any combustion of coal and natural gas that does not include carbon capture and storage (CCS).[6]

Another reason is that Canada is less likely to turn to large hydro and nuclear power for massive expansion of zero-emission electricity. Most of Canada's development of these two dominant sources occurred over 40 years ago, when there was less public concern for flooding of valleys, land rights of Indigenous Peoples, risks of nuclear power plant accidents and safe storage of radioactive waste. Today, political leaders have are generally more reluctant to face the challenges of siting and constructing new large nuclear and hydro plants. This reluctance has been reinforced by major cost overruns at two large hydro projects currently under construction: Muskrat Falls in Labrador and Site C in British Columbia.[7,8]

Fortunately, virtually all regions of southern Canada have potential for significant development of zero-emission renewable electricity from wind, solar and biomass, and several regions also have significant potential for small hydro and geothermal. However, three of these sources — wind, solar and small hydro — are challenged because their generation is "non-dispatchable" (meaning that their output varies depending on hourly, daily and seasonal weather conditions

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[5] Bataille, C. et al. (2015). *Pathways to Deep Decarbonization in Canada*, SDSN - IDDRI. https://www.iddri.org/sites/default/files/old/Publications/CAN_DDPP_report.pdf
Trottier Energy Futures Project. (2016). *Canada's Challenge and Opportunity: Transformations for major reductions in GHG emissions.* https://iet.polymtl.ca/wp-content/uploads/delightful-downloads/TEFP_FinalReport_20160425.pdf
Dion, J. et al. (2021). *Canada's Net Zero Future: Finding our way in the global transition*. Canadian Institute for Climate Choices. https://climatechoices.ca/reports/canadas-net-zero-future/

[6] Most cost estimates of these options include equipment to prevent other negative environmental effects such emissions of particulates, NO_x, SO_x and other criteria air contaminants. Most cost estimates do not assume further decreases in the commodity costs of coal and natural gas, although this is likely as their markets contract.

[7] Advocates of small modular reactors (SMRs) suggest that these plants will be more acceptable to the public, but there has yet to be a real-world test case and previous public reactions to conventional nuclear power suggest that this optimism may be overstated.

[8] The Gull Island project in Labrador is likely the only large hydro project that could potentially be built in Canada in the coming decades; however, the business case for the project continues to be uneconomic due to insufficient domestic demand and challenging inter-provincial trade negotiations.

regardless of the peak reliability needs of the electricity system at any given time). As these sources become more widespread, greater complementary investment is required in energy storage, of which there are many options, including co-ordination with existing hydro reservoirs, pumped hydro storage, compressed air storage, large battery banks or standby thermal generators that burn cleanly produced hydrogen, biomethane or perhaps natural gas with CCS.[9] Thus, while the installed costs of wind and solar projects have fallen dramatically over the past two decades, the total cost of electricity may rise in future as these non-dispatchable sources grow in importance.[10] This means that to achieve a zero-emission energy system, with its rapidly growing electricity demand, Canada faces challenges similar to most countries: it must have public policies that prevent investment in GHG-emitting coal and natural gas plants, unless these include effective CCS.[11]

1.2 Challenges to designing zero-emission electricity policy for Canada

Our primary objective in this report is to design and assess policies for achieving a zero-emission electricity system for all of Canada in less than two decades. While there are several policy options, an important challenge is Canada's federal system of government and the fact that its constitution allocates ownership of energy resources and most regulation of electricity to the provincial governments.[12]

With electricity mostly under provincial jurisdiction, the electricity system in most provinces is at least partly owned and operated by electric utilities that are provincial Crown corporations. And most provinces have utility commissions (quasi-judicial regulatory agencies) that regulate investments and rates of the few privately owned electric utilities and, to some degree, even the provincially owned electric utilities. The federal government's jurisdiction is limited to regulating infrastructure for the transport of energy across provincial or national borders — oil and gas pipelines, high-voltage transmission lines, port facilities — a function performed by its Canadian Energy Regulator (formerly the National Energy Board).

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[9] There are also options for demand-side response by consumers who vary the timing of their consumption to meet system needs, including allowing the system operator to "borrow" their electric vehicle batteries for electricity storage.

[10] Bistline, J. (2017). Economic and technical challenges of flexible operations under large-scale variable renewable deployment. *Energy Economics, 64*: 363-372. pg. 364.

[11] While the focus is on preventing the burning of coal and natural gas without CCS, there is also the potential to generate electricity by burning oil products, such as diesel, gasoline and propane. This practice is still common in remote communities and individual households that are not connected to an electricity distribution grid. In this short report, we do not address this issue.

[12] While the three northern territorial governments do not have the same jurisdictional authority over energy as provincial governments, Canada's federal government has devolved to them some responsibilities. But as these territories have unique electricity challenges and yet represent less than one per cent of the Canadian population, our focus in this brief report is the challenges for federal zero-emission policy in relation to the provincial governments.

If all provincial governments were committed to complete transition to a zero-emission electricity system, the federal government would happily play a co-ordinating role. It appeared to succeed with this approach when it negotiated the Pan-Canadian Framework with provincial governments in 2016.[13] However, while this framework still exists, some provincial governments no longer agree with the federal government's targets and policies. Indeed, it seems extremely unlikely that Canada's federal government and all 10 provincial governments would be in unanimous agreement for three straight decades on GHG targets and policies.

This explains why the federal government has been implementing "backstop" policies to ensure a comprehensive Canadian effort in pursuit of national GHG targets, a strategy that the courts have thus far interpreted as consistent with its authority under the Canadian Constitution. Thus, the federal government uses its environmental protection authority to regulate CO_2 as a pollutant under the *Canadian Environmental Protection Act 2016* (CEPA).[14] And it uses its "peace, order and good government" authority to price CO_2 under the *Greenhouse Gas Pollution Pricing Act 2018* (GGPPA).[15] The constitutional legitimacy of this latter act was confirmed in March 2021 by the Supreme Court of Canada.[16]

The Canadian government can continue its application of these two acts to achieve a nationwide zero-emission electricity system. First, using its regulatory powers under the CEPA, the federal government could require that by some future date all electricity-generating facilities in Canada have a carbon emission intensity of 0 g CO_2/kWh. Second, using its carbon-pricing powers under the GGPPA, the Canadian government could continue increasing the carbon price on CO_2 emissions from electricity until that price was so high that the combustion of fossil fuels without CCS was uneconomic relative to zero-emission alternatives. Third, the Canadian government could continue its current path of applying both policies in concert to achieve the zero-emission outcome.

This latter approach is notable because governments frequently apply more than one policy in pursuit of an objective like GHG reduction. In addition to regulation and carbon pricing, they may provide financial support like direct subsidies and tax credits to private and public entities, make major government direct investments and provide information programs and other forms of assistance. These additional policies are sometimes justified because of additional policy objectives, such as reconciliation with Indigenous Peoples, transitional support for impacted workers and regions, intertie challenges related to Canada's provincially fragmented electricity system, and potential benefits from fostering innovation that decreases the costs of achieving zero-emission electricity.

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[13] Environment and Climate Change Canada. (2016). *Pan-Canadian Framework on Clean Growth and Climate Change: Canada's plan to address climate change and grow the economy*. http://publications.gc.ca/collections/collection_2017/eccc/En4-294-2016-eng.pdf

[14] *Canadian Environmental Protection Act*, S.C. 1999, c. 33.

[15] *Greenhouse Gas Pollution Pricing Act,* S.C. 2018, c. 12, s. 186.

[16] *References re Greenhouse Gas Pollution Pricing Act*, 2021 SCC 11

In a report of this length, it is impossible to explore in detail all policy objectives and options in the transition to an expanding zero-emission national electricity system. Our goal here is limited to providing a high-level assessment of a strategic federal policy path to zero-emission electricity in Canada. To that end, building on the overview of the policy challenge in this first section, this report also contains sections on:

- an overview of the Canadian electricity system and provincial GHG policies,
- a review of federal policy options for nationwide zero-GHG electricity, and
- a simulation of two technology pathways that illustrate possible policy effects.

2 The Canadian electricity generation system and GHG-related policies

In this section we provide a snapshot of generation resources in each province and territory, as well as major grid interconnections between systems, and a summary of the ownership of these resources and the regulatory models for managing them, including GHG regulation.[17,18] Our generation estimates include stand-alone electricity generation, industrial cogeneration and urban combined heat and power systems. Our source for this secondary electricity generation is the Canadian Energy and Emissions Data Centre, which we operate. It provides Canada's only publicly available comprehensive data on the cogeneration of heat and electricity.[19]

The heterogeneity of electricity generation across Canada is remarkable. Four provinces that rely on hydropower are interspersed with five provinces that still generate varying amounts of electricity from thermal sources — nuclear, coal and natural gas — while the 10th province, Prince Edward Island, relies significantly on wind. There are grid connections between provinces and with the U.S., but the amount of electricity traded is small compared to total generation. Figure 1 provides the 2019 provincial and territorial breakdown of generation.

[17] Generation types and amounts are primarily from Statistics Canada (various tables). Electricity export connections and amounts are from the Canadian Energy Regulator. https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/electricity/index.html. Accessed 13 May 2021.

[18] Descriptions of Canada's northern territories are provided in Appendix A. Much of the electricity generated in the territories is in remote communities with unique challenges not faced in other regions connected to provincial grids. Because of this difference, and because the amount of electricity generated in the territories is very small compared to most provinces, we do not explicitly forecast electricity generation for the territories in our analysis.

[19] Canadian Energy and Emissions Data Centre. https://www.sfu.ca/ceedc.html. Accessed 13 May 2021.

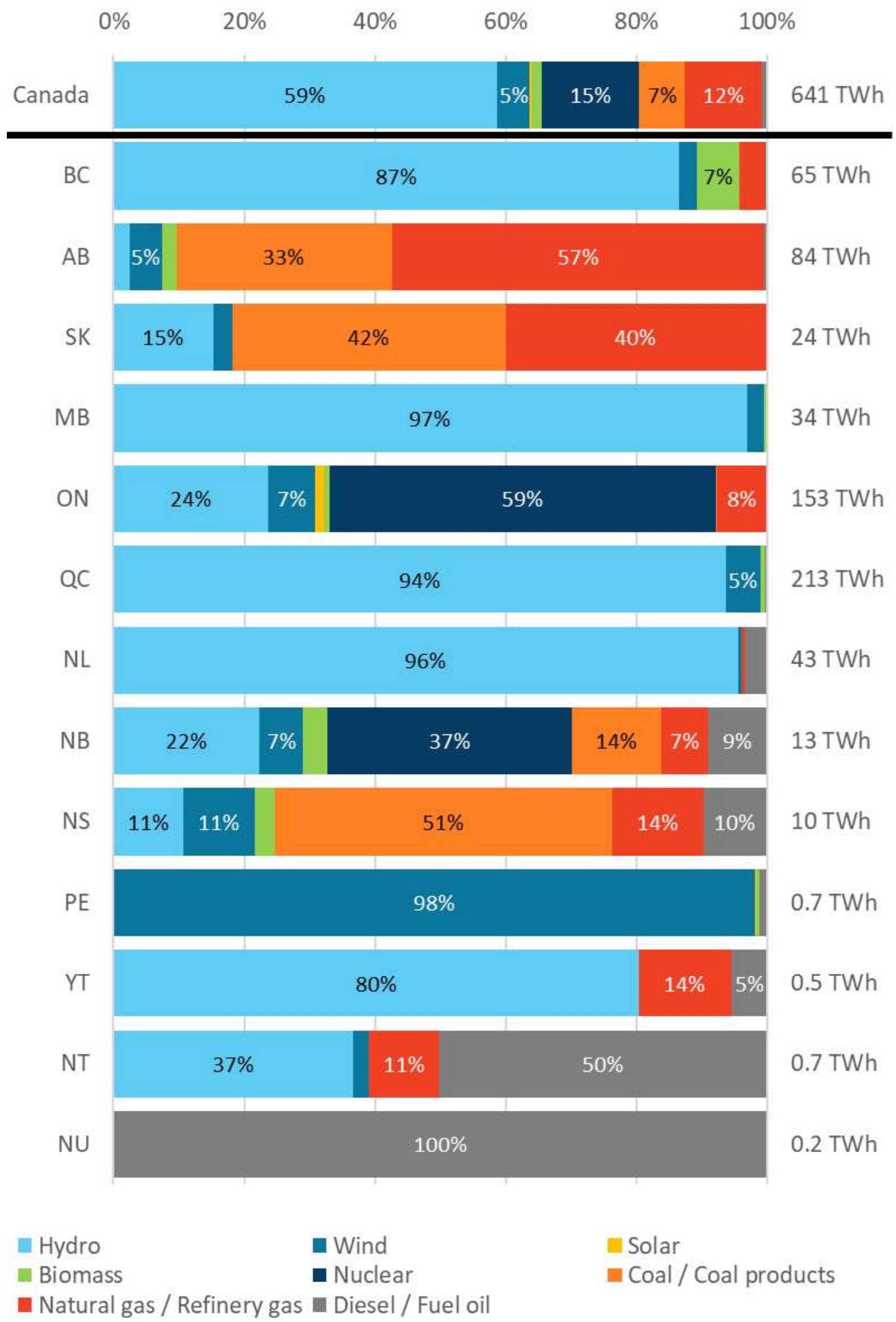

Figure 1: Electricity generation by region and type in 2019

Source: Canadian Energy and Emissions Data Centre

Not only are generation sources diverse among Canada's provinces, so too are ownership and regulation. The following sections summarize each province, with the Atlantic provinces covered by a single section.

2.1 British Columbia

The electricity system in British Columbia is dominated by hydroelectricity, with smaller contributions from biomass, wind, solar and natural gas, as well as diesel used in off-grid communities. Most of the hydropower is generated at a few large dams on the Peace and Columbia Rivers, which are owned by BC Hydro (Crown corporation). Some larger hydro facilities are also owned by aluminum and pulp and paper producers. A new 1,100 MW hydro facility on the Peace River, Site C, is scheduled for completion in 2025. BC Hydro also operates or purchases electricity from natural gas–burning industrial facilities.

Most biomass generation is at industrial pulp and paper facilities and relies on waste from B.C.'s forest industry and spent pulping liquor from the paper-making process. This biomass power usually comes from cogeneration plants that also produce steam for industrial use. Finally, independent power producers operate several run-of-river hydroelectric plants as well as all wind and solar facilities.

B.C. trades electricity primarily with the U.S., and to a lesser extent Alberta. On an annual basis, B.C. is typically a net exporter of electricity, except in years of unusually low winter precipitation. Total trade ranges between 1 TWh net imports to 5 TWh net exports.

The British Columbia Utilities Commission regulates BC Hydro and the Fortis electric utility in the province's southeast. B.C.'s *Clean Energy Act 2010* requires BC Hydro to generate at least 93 per cent of its electricity from designated clean or renewable sources.

2.2 Alberta

Alberta has a different electricity system than most provinces in that generation is dominated by large private and municipal utilities instead of a single provincial Crown corporation. Until 1996, large utilities were vertically integrated, but in that year the government created a competitive generation market operating through the Power Pool of Alberta.

In 2019, about 90 per cent of Alberta's 84 TWh of electricity was produced from fossil fuels — 57 per cent from natural gas and 33 per cent from coal. The rest was provided by renewables, such as wind, hydro and biomass. Coal-fired generation in Alberta is scheduled to be phased out by 2030, but this target will likely be achieved sooner as some former coal-fired facilities are undergoing conversion to natural gas. Alberta produces over half of Canada's cogenerated electricity. The majority is from combustion of natural gas in the oil and gas industry, with most of this capacity installed in the past two decades.

The Alberta Energy System Operator manages the Alberta electricity system, and the Alberta Utilities Commission regulates privately owned utilities. More than 200 Alberta electricity market participants are registered with the system operator.

Under Alberta's Technology Innovation and Emissions Reduction regulation, electricity facilities must comply with a sector-wide GHG performance benchmark equivalent to "good-as-best gas" facilities, that being 370 g CO_2/kWh. Regulated facilities have four compliance options: improve the GHG intensity of their operations, buy emissions performance credits from other regulated facilities, buy Alberta-based offsets or pay a government charge of \$30/tCO_2 for emissions in excess of the benchmark.[20]

Alberta's Renewable Electricity Program established in 2016 a competitive bidding market for required new renewable generation, the extra costs of which would be recovered from all customers. By 2019, when it was suspended by a new government, the program had incentivized investment in 1,100 MW of renewable capacity.

Alberta's Micro-Generation Regulation allows Alberta residents to generate electricity from renewable sources and sell the surplus to the grid. As of February 2019, micro-generation accounted for 44 MW of capacity across more than 3,000 sites, with solar accounting for approximately 90 per cent of this capacity.[21] Alberta trades electricity with B.C., Saskatchewan and Montana and generally has net imports of about two to 4.5 TWh.

2.3 Saskatchewan

Like Alberta, Saskatchewan has an electricity system that is mostly based on fossil fuels: of the 24 TWh generated in 2019, coal provided 42 per cent and natural gas 40 per cent. Boundary Dam is Saskatchewan's largest coal-fired power plant. Of its 672 MW of coal-fired capacity, 115 MW was retrofitted in 2014 with CCS that removes up to 1 Mt CO_2/year. While Saskatchewan has interconnections with Alberta and the U.S., its trade balance is generally close to zero.

Most generation capacity and all transmission and distribution in Saskatchewan is owned and operated by the Crown corporation, SaskPower. Independent power producers account for the remaining 20 per cent of generation capacity. In terms of future zero-emission electricity, southern Saskatchewan has some of the best solar and wind potential in Canada.[22]

2.4 Manitoba

In 2019, 97 per cent of Manitoba's 33 TWh of electricity was generated from hydropower with wind making a small contribution. In 2018, the last coal-fired generating unit in Manitoba ceased operation. Currently, Manitoba Hydro and some First Nations are collaborating on the 700 MW Keeyask hydro project. Manitoba's net electricity interprovincial and international exports are generally about 9 TWh, mostly because of dedicated exports to the U.S.

Manitoba Hydro, a Crown corporation, is responsible for the ownership and operation of hydro facilities and a few small natural gas and remote diesel units, as well as electricity transmission and distribution. Wind, biomass and some solar facilities are operated by independent power producers. The Manitoba Public Utilities Board partly regulates Manitoba Hydro.

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[20] It is unclear how or if this rate will rise at the same rate as the scheduled rise in the federal carbon tax.

[21] Canadian Energy Regulator. https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-alberta.html. Accessed 13 May 2021.

[22] The World Bank. (2019). *Global Solar Atlas 2.0, Solar resource data: Solargis*. https://globalsolaratlas.info/download/canada.

2.5 Ontario

Ontario relies primarily on non-emitting sources: 60 per cent from nuclear, 24 per cent from hydro and seven per cent from wind. Natural gas provides roughly the same generation as wind power. In 2019, Ontario generated 153 TWh of electricity, 23 per cent of total Canadian generation. Ontario has about one-fifth of Canada's cogeneration capacity, which is roughly split between public and private utilities and the industrial sector.

Three nuclear facilities with a combined capacity of 12.6 GW provide the bulk of Ontario's baseload generation and almost all of Canada's nuclear power. Bruce Power and Ontario Power Generation operate the three nuclear facilities at Bruce, Darlington and Pickering. The latter is scheduled to retire in 2025.

Ontario leads Canada in the installation of smaller renewables like wind and solar, although Quebec produces about the same amount of wind power from a smaller installed capacity. About six GW of wind capacity and three GW of solar PV capacity were added by 2019. Ontario has almost all the installed solar capacity in Canada. Ontario also has the largest 100 per cent biomass-fuelled plant in North America, the 205 MW Atikokan Generating Station, which was converted from coal in 2014.

Ontario's net electricity exports are usually 12 to 14 TWh, about eight per cent of total generation. The province has interconnections with Manitoba, Quebec and the U.S. Most imports come from Quebec, while most of Ontario's exports go to the U.S.

Ontario Power Generation, a Crown corporation, is the largest generator in Ontario's competitive electricity market, providing over half. Hydro One owns and operates almost all of Ontario's transmission and is also the largest distributor of electricity (26 per cent of customers), but otherwise electricity distribution is dominated by 60 municipal utilities. The Independent Electricity System Operator manages the province's power system, and the Ontario Energy Board regulates much of the electricity sector.

2.6 Quebec

Quebec's hydroelectric plants, owned by the Crown corporation Hydro-Québec, produced 94 per cent of the province's 213 TWh of electricity in 2019, alongside small contributions from wind, biomass, natural gas (for peak winter demand) and diesel in off-grid communities. Hydro-Québec is also working to to transition off-grid communities from diesel to small renewable energy projects. Quebec accounts for 33 per cent of total Canadian generation.

Compared to British Columbia, a region with a similarly large forestry industry, Quebec produces relatively little electricity from biomass (one per cent) and industrial cogeneration (two per cent). Quebec is the largest exporter of electricity to the U.S., reaching 29 TWh in high-water years. And Hydro-Québec has access to much of the output of Churchill Falls hydropower in Labrador from long-term contracts that terminate in 2041, resulting in large interprovincial electricity imports.

The Régie de l'énergie partly regulates Hydro-Québec. The province belongs to an economy-wide GHG cap-and-trade system with California, which includes any electricity generator annually emitting 25,000 tonnes of CO_2. Options for emitters are to reduce emissions or purchase emission allowances in the allowance trading market. A rising floor price in the regulation ensures that allowance prices (in $/t$CO_2$) rise over time.

2.7 Atlantic provinces

New Brunswick's 13 TWh of electricity consumption in 2019 was 37 per cent from nuclear, 30 per cent from fossil fuels (natural gas, coal and petroleum), and 33 per cent from renewables (hydro, wind and biomass). Interconnected with P.E.I., Quebec and Maine, the province exports or imports up to 10 per cent of its total generation, depending on the year. NB Power, a Crown corporation, owns almost 90 per cent of the province's generating capacity, with the rest belonging to independent producers. New Brunswick has a renewable portfolio standard that requires an increase to 40 per cent of electricity from renewable sources.

Nova Scotia's 10 TWh of electricity consumption in 2019 was 60 per cent from coal, but this share is declining as the renewables share grows. The province currently imports about five per cent of its electricity from New Brunswick, but with the 2018 completion of the 500 MW Maritime Link transmission line connecting to Labrador's Muskrat Falls, Nova Scotia's imports of hydroelectricity will grow substantially under long-term supply contracts (35 years) once that project is completed. Nova Scotia Power, which generates most of the province's electricity, is regulated by the Nova Scotia Utility and Review Board. Both Nova Scotia Power and Maritime Link are subsidiaries of Emera, a private company.[23] Nova Scotia has an emissions cap-and-trade program, which includes electricity generation. A declining cap on emissions from major emitters means that maximum industrial emissions must fall from 7.5 in 2020 to 4.5 Mt CO_2e in 2030, with electricity generation accounting for over half of these emissions. The province also required 40 per cent of electricity to be generated from renewables by 2020.

Prince Edward Island's 2 TWh of electricity consumption in 2019 was met 50 per cent from local wind power and 50 per cent from imports from New Brunswick, with on-island diesel and oil-fired facilities available if wind and imports are insufficient. P.E.I. Energy, a provincial Crown corporation, and some independent generators operate eight wind farms. The province's Renewable Energy Act provides a minimum price that utilities must pay for wind power, incentivizing a growth in capacity from 15 MW in 2005 to 205 MW in 2018. The Island Regulatory and Appeals Commission regulates electric utilities in the province.

Newfoundland and Labrador's 10 TWh of electricity consumption was provided almost exclusively from hydro sources (96 per cent) in 2019. With the completion in 2018 of the Labrador-Island Link and the Maritime Link, Newfoundland is now connected to the North American grid by a transmission line through Quebec and another through Nova Scotia. This will enable electricity from Muskrat Falls in Labrador, when completed, to supply its own province and other Maritime provinces (notably 20 per cent of its output to Nova Scotia under a 35-year supply agreement). Electricity from the large hydro facility at Churchill Falls in Labrador, completed in 1974, is mostly exported to Hydro-Québec under a long-term contract

[23] Emera. https://www.emeranl.com/maritime-link/overview. Accessed 13 May 2021.

that expires in 2041. Thus, in 2019 about 30 TWh of the total generation in Newfoundland and Labrador of 43 TWh was exported. Newfoundland and Labrador Hydro (a subsidiary of Nalcor Energy) is the provincial Crown corporation responsible for most generation and transmission in the province, while Newfoundland Power, owned by Fortis Inc., is the electricity distribution utility. Newfoundland and Labrador's Board of Commissioners of Public Utilities is the regulator.

3 Options for Canada-wide zero-emission electricity policy

3.1 The rationale for federal backstop regulation or pricing of electricity emissions

Across Canada, two decades of provincial policies have decreased electricity system GHG emissions. Increased generation from large hydro, nuclear, low-emission cogeneration, biomass, wind, solar and run-of-river hydro has displaced coal, oil and in some cases natural gas–fired power. Additionally, some high-emission coal plants are being replaced by lower-emission natural gas, and in one case CCS was added to an existing coal plant. What was already a low-emission national electricity system has nonetheless seen its total emissions fall (Figure 2) even as total generation increased.

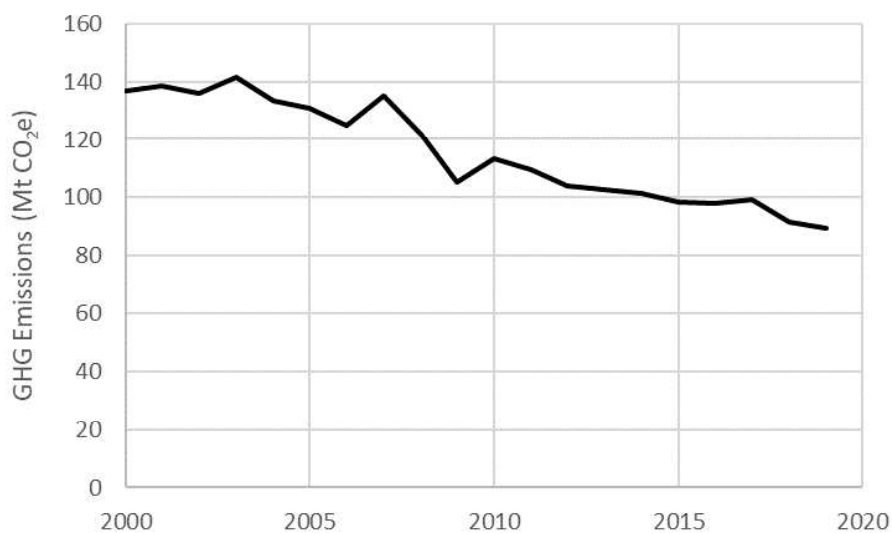

Figure 2: Utility and industry generated electricity GHG emissions in Canada: 2000-2020

Source: Report on Energy Supply and Demand, Statistics Canada; Authors' calculations

This 20-year transition toward lower-emission national electricity has been driven almost entirely by provincial policies. In 2004-2014, the Ontario government decommissioned its coal plants, representing 25 per cent of the province's generation, converting one of them to biomass. In 2007, the B.C. government initiated a clean electricity requirement that prevented construction of two proposed coal plants and one natural gas plant. Governments in Atlantic Canada invested in hydropower and new grid interties while implementing policies to support wind and other renewables that resulted in decreased coal plant output. In 2009-2014, Saskatchewan became a world leader by retrofitting an existing coal plant with CCS. Quebec has been developing wind power to operate in tandem with its hydropower. And, in 2015, when coal still provided 50 per cent of Alberta's electricity, its government promised to eliminate coal-fired power by 2030, a goal it could achieve five years earlier than promised.

Given these provincial initiatives, and the resulting downward trend in emissions, one could argue that the Canadian federal government need not implement policies to ensure a future zero-GHG national electricity system. However, two related factors undermine this assumption.

First, the path to net-zero GHG emissions is forecast by most experts to include a dramatic increase in electricity generation. In Figure 3 we show a forecast for Canadian electricity demand that we produced by averaging four recent studies simulating Canada's path to net-zero GHG emissions by 2050. By including 30 years of historical electricity consumption, the figure illustrates the dramatic increase in generation that is required. Our average value forecast shows Canadian total generation doubling from about 600 TWh in 2020 to 1,200 in 2050. This increase of about 600 TWh in the next 30 years is six times greater than the 100 TWh increase during the previous 30 years.

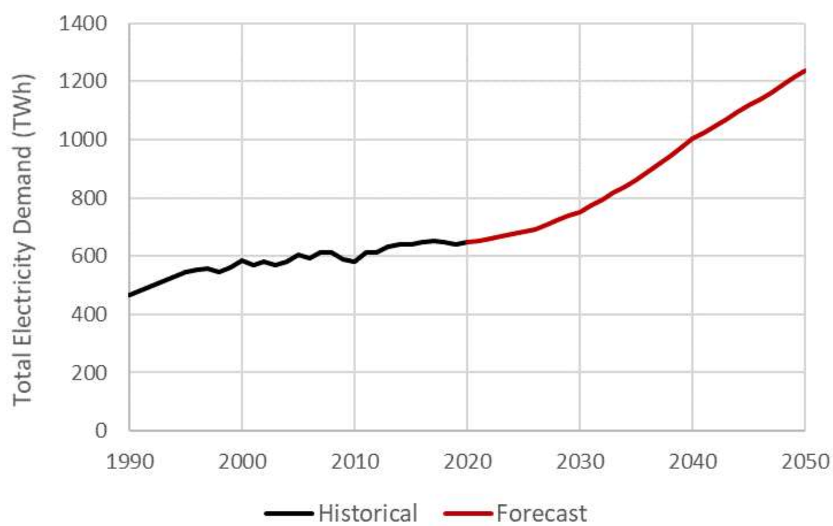

Figure 3: Canadian electricity demand on path to net-zero: 1990-2050

Source: Statistics Canada (various tables); Authors' forecast

Moreover, we note that the studies we used for our electricity demand forecast all include an assumption of strong energy efficiency improvements across the whole economy. Thus, our forecast includes substantial conservation behavioural changes by consumers to reduce all final energy demand, including electricity. It also includes significant efficiency improvements in electricity use in equipment, appliances, buildings and industrial processes. Finally, energy efficiency also improves significantly because of energy substitution; electricity-using technologies like electric vehicles and heat pumps have dramatically higher energy efficiency than the fossil fuel burning technologies they replace. As one example of these dramatic conservation and efficiency gains, *The Pathways to Deep Decarbonization in Canada* (2015) report anticipates a 50 to 60 per cent reduction in the energy intensity of GDP by 2050.[24] In a net-zero future, electricity consumption doubles despite a dramatic increase in energy efficiency.

Second, there is no guarantee that every provincial government will agree for 30 straight years that Canada's rapidly growing electricity system must have net-zero GHG emissions. They certainly don't agree today. Thus, while phasing out coal, the Ontario government allowed the construction of new natural gas plants, a development that is likely to continue. And although the Saskatchewan and Alberta governments today support substituting coal-fired electricity generation with natural gas, they have no plans to phase out the use of natural gas generation in the next decade, and indeed may support its increasing role to meet growing electricity demand. Plentiful natural gas in Canada is among the cheapest options for dispatchable electricity today and likely into the future — in the absence of strong GHG policies.

Alberta's approach of including the electricity sector in its provincial industrial carbon pricing policy results in a carbon price being applied to only a percentage of emissions — the amount by which each generator's emissions exceed a benchmark performance standard.[25] The effect is to incentivize GHG reductions without causing a dramatic increase in electricity rates for final consumers. This policy is motivating a shift toward natural gas generation but does not establish incentives for eventually reaching zero-emission electricity. Indeed, it may make zero-emissions in 2030 or 2035 more difficult to achieve if substantial investments are made over the next decade in long-lived natural gas power plants.

Figure 4 shows the historical increase in natural gas generated electricity in Canada from 2000 to 2019 and simulates continued generation increases to 2035 under the assumption that announced new investments and conversions to natural gas are completed and operating over this decade. If Canadian electricity consumption is to approximately double in a net-zero GHG future and if some provincial governments are unwilling to forego major investments in natural gas generation to meet this growing demand, Canada will not be on a net-zero path to 2050.

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[24] Bataille, C. et al. (2015). *Pathways to Deep Decarbonization in Canada*, SDSN - IDDRI. https://www.iddri.org/sites/default/files/old/Publications/CAN_DDPP_report.pdf

[25] As noted earlier, this is called the Technology Innovation and Emissions Reduction Regulation, which functions similarly, but not identically, to the federal Output Based Pricing System for industry.

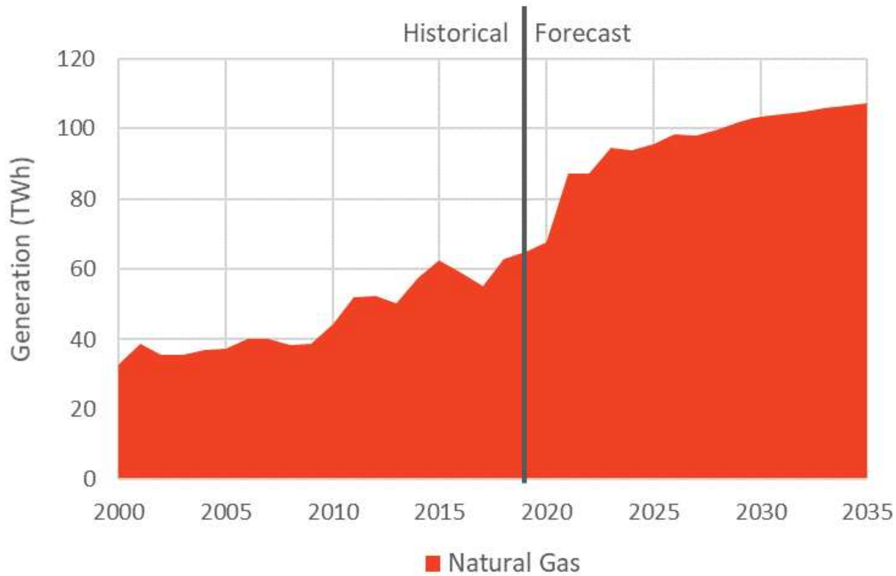

Figure 4: Canadian electricity generation from natural gas: 2000-2035 (Reference forecast)

Source: Statistics Canada (various tables); Authors' forecast

As noted, the Supreme Court of Canada has recognized federal authority to make a national GHG commitment and implement regulations and carbon pricing to ensure a nationwide effort that meets this commitment. The court was clear, however, that the federal government does not have authority over the ownership, investment, operation and regulation of electricity, which is under provincial jurisdiction.[26] And the court has signalled that the Canadian government should implement its GHG policies in a manner that recognizes its shared environmental authority with the provinces.

Consequently, the federal government has interpreted its role as one of first trying to coordinate the GHG-reducing efforts of all provinces toward a national target. The Liberal governments of Jean Chretien (1993-2003) and Paul Martin (2003-2006), the Conservative government of Stephen Harper (2006-2015) and the Liberal government of Justin Trudeau (2015-present) have involved provincial governments in multiple efforts to develop national climate plans over the past 30 years.[27] As noted, the most recent manifestation of this approach is the Pan-Canadian Framework negotiated in 2016 by the federal and provincial governments.

This overlap of federal and provincial environmental authority helps explain the approach of the Harper government in 2012 as it developed a nationwide emission performance standard

[26] The federal government also has authority over cross-border electricity trade, which we discuss later.

[27] See Simpson, J., Jaccard, M. and N. Rivers (2007) Hot Air: Meeting Canada's Climate Change Challenge.

for electricity plants that would require eventual closure of all conventional coal plants.[28] The policy set an emission limit for coal plants of 420 g CO_2/kWh, effectively prohibiting coal plants that lack CCS. In contrast, most efficient natural gas plants meet the standard. The government tailored this regulation to recognize each province's unique circumstances in terms of the age of its coal plants. Newer plants were exempt until an expected "natural retirement" date, meaning that some plants could potentially keep operating (and emitting) until 2042.

Similarly, when the Liberal government of Justin Trudeau tightened this same regulation in 2016, by replacing the age exemption with a firm limit of 2030 for compliance with the performance standard, it was willing to negotiate "equivalency agreements" with provinces that had policies of similar stringency and possibly higher transitional costs. Thus, it reached an agreement with Saskatchewan to allow some conventional coal plants to operate after 2030 and a similar agreement with Nova Scotia that could allow some coal-fired power until 2040.

The federal government's rationale was that the costs of decarbonization are higher in the electricity sector of these jurisdictions, so allowing extra transitional time is warranted in terms of policy equity. And if the provincial governments relax their commitments, the federal government has a national policy waiting as a "backstop." In other words, the federal government is willing to step aside in any sector of the economy where provincial policies are generally consistent with achieving national GHG objectives, but it will apply its backstop policy where it deems that a provincial government is not making serious progress on implementing an equivalent policy.[29]

As shown above in Figure 4, natural gas–generated electricity can increase in some provinces under current federal and provincial policy. Yet Canada's Pan-Canadian Framework set a target that 90 per cent of electricity would be generated by zero-emission sources by 2030.[30] And net-zero analysis, such as that conducted in 2021 by the Canadian Institute for Climate Choices, indicates that the share of net-zero electricity generation should reach almost 100 per cent by 2035 if Canada is to follow a trajectory that achieves its 2050 net-zero target.[31] Federal

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[28] Regulation Amending the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity, SOR/2018-263. https://gazette.gc.ca/rp-pr/p2/2018/2018-12-12/html/sor-dors263-eng.html

[29] The federal government uses the term "backstop" when describing the role of its carbon pricing policies. When it implemented a backstop carbon price in 2018, the federal government exempted Quebec (cap-and-trade) and B.C. (carbon tax) from this policy. It initially also exempted Alberta (carbon tax) and Ontario (cap-and-trade), but when new provincial governments eliminated these policies, the backstop carbon price was applied. In 2021, the federal government has been negotiating carbon pricing equivalency agreements with New Brunswick and Manitoba.

[30] Environment and Climate Change Canada. (2016). *Pan-Canadian Framework on Clean Growth and Climate Change: Canada's plan to address climate change and grow the economy*. http://publications.gc.ca/collections/collection_2017/eccc/En4-294-2016-eng.pdf

[31] Dion, J. et al. (2021). *Canada's Net Zero Future: Finding our way in the global transition*. Canadian Institute for Climate Choices. This study shows net-zero simulations (without significant direct air capture and storage of CO2) in which zero-emission electricity generators provide all but 1-2% of electricity nationally. https://climatechoices.ca/reports/canadas-net-zero-future/

electricity GHG policy needs to increase in ambition if the government is to keep its commitments.

3.2 Options for federal backstop pricing or regulation of electricity emissions

To reduce GHG emissions from Canada's electricity sector, the federal government has been willing to use its own carbon pricing and regulations or instead allow equivalent provincial policies. In this section, we explain how either (or both) of these policy approaches can increase in stringency to transition the Canadian electricity system to 100 per cent zero-emission and sustain it as the system doubles on the path to a net-zero Canadian economy in 2050.

3.2.1 Transition to carbon pricing of all electricity GHG emissions

Economists have long shown that pricing a global pollutant like CO_2 (and other GHGs) is the most cost-effective way to achieve a given GHG reduction target. This is because the carbon price signals the harm caused by the pollutant but does not prescribe how firms and households should respond to the resulting price increases it causes for polluting fossil fuel energy products and other products produced from burning fossil fuels, such as electricity generated by coal and natural gas. Each firm and household can determine its response, if any, to the price increases, and those for whom GHG reduction is cheapest will do more, enabling society to achieve a given level of reduction at the lowest total cost.[32]

There are two policy options for carbon pricing. Government can charge a carbon tax. Or it can cap emissions by regulation and allocate tradable emission permits that in total equal the cap — called "cap-and-trade." Over time, government lowers the cap by reducing the available permits each year. And because these permits are tradable, their cost for purchasers has the same upward effect on the price of polluting energy forms and other goods as would a rising carbon tax. The cost of the permit incentivizes many households and firms to shift toward technologies and behaviours that emit less GHGs, in the same way as the carbon tax.

The least costly way to achieve a national target is to apply the same carbon price to all GHG emissions in all sectors. Every GHG emission in a jurisdiction (whether sub-national, national or a coordinated group of countries like those of the European Union) would be charged a carbon tax, or every GHG emission in a cap-and-trade program would require the purchase of a permit. That is the ideal. In the real world, however, there are constraints to one country, or even a group of countries, applying a single carbon price to every domestic emission.

First, a carbon price charged to every GHG emitted by Canada's emission-intensive and trade exposed (EITE) industries — steel, cement, aluminum, bulk chemicals, non-ferrous metal smelting, pulp and paper, oil and gas production — would increase their cost of production relative to competitors in countries with less-aggressive climate policies. Governments recognize this challenge by exempting these industries from comprehensive carbon pricing,

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[32] Canada's Ecofiscal Commission (2014-2019) produced several reports illustrating the advantages of carbon pricing relative to regulations, especially if these latter are inflexible. https://ecofiscal.ca/.

either by applying the carbon tax to only a percentage of their emissions or by allocating free emission permits under cap-and-trade.[33]

Second, while the costs of GHG emissions reduction are similar across Canada in some sectors, such as transport and buildings, the costs are not similar in the electricity sector.[34] As our survey of electricity generation across Canada showed, the initial costs of transitioning to a zero-emission electricity system are almost zero in hydropower-dominated provinces while this is not the case in provinces reliant to some extent on coal and natural gas. Ever since GHG emissions first became a national priority in the 1990s, federal governments have recognized the need for differentiated treatment of the provinces when it comes to the electricity sector. Hence the geographically distinct approaches to electricity GHG policy by first the Harper government and then the Trudeau government.

But while this differentiated treatment of provinces during the initial transition to zero-emission is understandable, the necessarily rapid expansion of zero-emission electricity in the 2030 to 2050 period offers little room for regional policy diversity. If the federal government relies on carbon pricing as its key policy, it needs a clear schedule indicating how its rising backstop carbon price will transition from the current application to only a percentage of electricity GHG emissions, as in the federal OBPS and its provincial equivalent policies, to its eventual application to all such emissions. If the federal government is unwilling to make this change to the OBPS applied to electricity, then it can instead remove electricity generators from the OBPS and apply its backstop carbon price to all GHG emissions of electricity generators, just as it does today with its fuel carbon price applied to vehicles, buildings and small-industry emissions.[35]

And to check mis-investment in new natural gas plants that lack CCS, the government should state soon the timeframe of this transition. We propose that Quebec, B.C., Manitoba, Newfoundland and Labrador and Prince Edward Island face a deadline of 2030 for 100 per cent application of the carbon price, while Alberta, Saskatchewan, Ontario, New Brunswick and Nova Scotia face a deadline of 2035.

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[33] Canada's Output Based Pricing System (https://laws-lois.justice.gc.ca/eng/regulations/SOR-2019-266/index.html) is an example of taxing only a percentage of emissions and Quebec's cap-and-trade system is an example of allocating some free emission permits to trade-exposed industries (https://www.environnement.gouv.qc.ca/changementsclimatiques/marche-carbone_en.asp).

[34] The costs for GHG reduction in buildings and transport are relatively even east to west in Canada, but not north to south. The northern territories have substantially higher costs of achieving zero-emission buildings and transport relative to the provinces. Also, the costs of GHG reduction in these sectors can differ significantly between residents of cities and towns relative to residents of more remote smaller communities, many of which are communities of Indigenous peoples.

[35] The necessity of this change to the OBPS, if applied to electricity generators in some provinces, is an obvious conclusion from challenges identified in the recent carbon pricing analysis of the Canadian Institute for Climate Choices. Sawyer, D., S. Stiebert, R. Gignac, A. Campney, and D. Beugin. (2021). *The State of Carbon Pricing in Canada: Key Findings and Recommendations*. Canadian Institute for Climate Choices. https://climatechoices.ca/reports/the-state-of-carbon-pricing-in-canada/)

Regardless of the precise timing and degree of regional differentiation, if explicit carbon pricing is the key policy for ensuring that a growing electricity sector is zero-emission, that same price must be applied to all electricity generation emissions within about a decade, and then must rise according to the federal backstop carbon pricing schedule. Provinces negotiating an equivalency agreement to rely on their own carbon pricing would meet or exceed the federal backstop carbon price while provinces negotiating an equivalency agreement to rely on their own cap-and-trade would ensure that the GHG cap in the electricity sector fell to zero on the date specified by the federal government, such as 2030 or 2035. Finally, in negotiating carbon pricing equivalency agreements, the federal government would allow trading where two or more provinces have absolute emissions cap-and-trade systems (e.g., Quebec and another province). In this case, however, the government needs to develop restrictive protocols before allowing trading with sectors outside of electricity. Electricity can and should be zero-emission.

The box summarizes key elements of a federal carbon pricing policy to achieve net-zero by 2035 and sustain it to 2050.

Carbon pricing approach to net-zero electricity

Federal backstop carbon price rises to \$170/tCO_2 in 2030, continuing to \$300/tCO_2 and perhaps higher in 2050. All electricity GHG emissions are subject to backstop carbon price by 2030 in provinces dominated by hydro-nuclear-wind and by 2035 in provinces that were still reliant on substantial coal or natural gas in 2020.

If OBPS or equivalent (e.g., TIER in Alberta) is the carbon pricing policy, it transitions to full application of the federal backstop carbon price or provincial equivalent by 2030 or 2035. This means that output-based standards for all electricity plants (whether coal-to-gas conversions, coal with CCS, older natural gas or new natural gas) would transition to 0 g CO_2/kWh by 2030 or 2035 depending on the province.

If cap-and-trade (e.g., Quebec) is the carbon pricing policy, the electricity cap falls to zero by 2030 or 2035. Trading between provincial electricity systems under cap-and-trade is allowed. Trading between sectors within or between provinces may be allowed, but must be controlled to ensure net-zero-emission electricity nationwide on a path to a net-zero-emission economy in 2050.

3.2.2 Transition to a national clean electricity standard

While explicit carbon pricing may be the most cost-effective way to achieve and sustain a zero-GHG national electricity sector, regulations can be designed that reduce GHG emissions while providing an “implicit” carbon price that increases the chance of cost-effective GHG reduction, especially when the end state is a sustained zero-emission electricity system. One possible regulation in electricity is the renewable portfolio standard. Applied in many countries and about half of U.S. states, this policy requires a rising percentage of electricity from renewable sources, and usually allows trading of renewable generation credits among electricity suppliers to ensure a more cost-effective outcome than would otherwise occur. The trading price of these credits can be linked to the resulting decrease in GHG emissions to calculate an implicit carbon price.

However, one concern with a renewable portfolio standard is that by prohibiting some zero-emission electricity options — such as nuclear power, coal or gas with CCS and (sometimes) large hydro — it excludes what may be, in some jurisdictions, lower-cost GHG reduction options. In contrast, a regulation that more closely approximates carbon pricing would allow (1) adoption of any zero-emission generation option (including ones with negative emissions like BECCS), and (2) zero-emission credit trading among electricity generators both within and between jurisdictions to reduce the total cost of compliance.

The Clean Power Plan (CPP) developed by U.S. President Barack Obama provides elements of a regulatory model for Canada's federal government.[36] The CPP was introduced in 2015 but stayed by the U.S. Supreme Court in 2016 pending judicial review, and then shelved by President Donald Trump in 2017. It is anticipated that President Joe Biden will resurrect it in some form in late 2021 or early 2022.[37] The CPP set CO_2 emission limits for electricity generation plants as a federal regulation under the U.S. Environmental Protection Agency. There are several complexities to the regulation, but for our purposes only a few elements need be described.

The CPP's intent was to reduce emissions from existing coal and natural gas power plants, while encouraging electricity efficiency along with substitution to lower- and zero-emission generation. The CPP operated like a backstop regulation in that it allowed states to (1) substitute their own policies to achieve a statewide carbon intensity limit (CO_2/kWh) or an equivalent absolute emission level (CO_2 cap), and (2) combine with other states in cases where increased electricity trade in their interconnected regional grids would enable them to collectively comply with the CPP at lower cost. By initially setting a unique carbon intensity limit or emissions cap for each state, the CPP recognized the heterogeneous nature of state electricity systems, thus reducing compliance cost differences between states. The CPP was also technology-neutral as a cost-minimizing strategy, with no a priori restrictions on the relative contributions to electricity GHG reduction from efficiency, renewables, large hydro, nuclear or coal and natural gas with CCS.

If the Canadian government opts to continue with its backstop regulatory approach for the electricity sector, we propose it combine elements of the U.S. CPP with its current carbon intensity performance standard under the Canadian Environmental Protection Act. This

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[36] https://archive.epa.gov/epa/cleanpowerplan/fact-sheet-overview-clean-power-plan.html

[37] There is great uncertainty and thus great debate today in the U.S. about the ultimate design and implementation of electricity GHG policy. While legislation is preferred by advocates of such policy, this might not be politically possible with the current composition of the U.S. Congress, meaning that such policy will be developed instead by the U.S. government's executive branch under the Environmental Protection Agency. The following two references address key design options. (1) Greenstone, M. and I. Nath (2021) Fueling Technology Deployment with a Clean Electricity Standard, Energy Policy Institute at the University of Chicago. https://epic.uchicago.edu/area-of-focus/fueling-technology-deployment-with-a-clean-electricity-standard/ (2) Piccianno, P., Rennert, K. and D. Shawhan (2020) Two Key Design Parameters in Clean Electricity Standards, Resources for the Future. https://www.rff.org/publications/issue-briefs/key-design-parameters-clean-electricity-standards/

approach can help the federal government navigate the 2020-2035 transition period, when electricity decarbonization costs are heterogeneous between provinces. Then, once all provincial electricity systems achieve zero emissions in 2030 or 2035, the federal backstop regulation would simplify to a prohibition on GHG-emitting generators anywhere in the country. At this stage, the policy would mimic the B.C. government's clean electricity requirement, which, when implemented in 2007, caused the cancellation of two proposed coal plants, a proposed natural gas plant and any future fossil fuel plants (without CCS), leading to the development instead of small hydro, wind and now large hydro after the 2013 government decision to construct the Site C dam.[38]

Specifically, we propose that the Canadian government change its carbon intensity performance standard for electricity generators (under its CEPA regulation) to 0 g CO_2/kWh by 2035 for all plants everywhere in Canada. While this would be the "clean electricity standard," there can be flexibility both within and between provinces, and over time during the transition to a growing zero-emission national electricity system. We suggest that the following elements would support the cost-effectiveness of this policy.

First, Canada needs to prevent mis-investment in natural gas generation that would soon require costly retrofit to add CCS. Thus, the carbon intensity performance standard for all new electricity generation plants would fall already in 2025 to 37 g CO_2/kWh. Only new natural gas plants with CCS can meet this standard.[39]

Second, Canada needs the electricity system in each province to transition to zero-emissions in the 2030-2035 timeframe and then retain that character as the economy decarbonizes and uses more electricity to 2050. But to recognize differing provincial conditions, the 2030 performance standard for generators in B.C., Manitoba, Quebec, P.E.I. and Newfoundland and Labrador would be 0 g CO_2/kWh, while in Alberta, Saskatchewan, Ontario, New Brunswick and Nova Scotia, it would be 37 g CO_2/kWh (thus requiring by 2030 the retrofit with CCS of all existing natural gas plants). Finally, in 2035, the performance standard of 0 g CO_2/kWh would apply to all provinces, meaning that natural gas plants with CCS would need to partner with negative-emission technologies that would offset their residual emissions.

Third, as with previous applications of this regulation, we propose that provinces be allowed to negotiate "total system" equivalency agreements. Thus, as noted above, natural gas plants with CCS in one province could invest in BECCS or direct air capture with CCS to create negative emissions that would cancel out the residual emissions of any remaining emitting plants.[40]

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[38] One of us (Mark Jaccard) advised the B.C. government in 2005-2007 when it implemented the first incarnation of this policy and again in 2009-2010 when it increased the policy's stringency.

[39] Note that we refer here to performance standards under the CEPA. These should not be confused with the output-based standards for coal-to-gas conversions, existing gas plants and new gas plants under the OBPS.

[40] Note that we refer here only to CO_2 extraction from the atmosphere and then injection underground. Currently, this is (1) BECCS and (2) possibly direct air capture technologies with storage. These geological sequestration technologies are needed, in addition to afforestation, soil enhancement and other means of biospheric carbon sequestration if humanity is to return from an atmospheric CO_2 concentration of 415 ppm (or likely much higher) back down to 350 ppm (or lower if necessary because of delay) during this century.

Moreover, we suggest that multi-province equivalency agreements should be encouraged so that neighbouring provinces collectively might achieve greater cost savings through system co-ordination and trade (similarly to the proposed U.S. Clean Power Plan).

For example, provinces with BECCS would receive negative-emission credits they could sell to provinces with residual emissions. Also, neighbouring provinces could gain from co-utilizing the massive energy storage in hydro reservoirs that will increase in value as a complement to growing wind and solar. Indeed, the growth of wind and solar generation will increase the incentive for neighbouring provinces to expand their grid interconnection capacities, which the federal government can facilitate through its regulation of interprovincial electricity transmission. We estimate dramatic reductions in the cost of achieving a net-zero national electricity system if the grid interties are expanded between neighbouring provinces with complementary systems — B.C. and Alberta, Saskatchewan and Manitoba, Ontario and Quebec, and among the Atlantic provinces as is already occurring with the recently completed transmission links.

The box summarizes key elements of a federal clean electricity performance standard (a clean electricity standard) to nationally achieve net-zero by 2035 and sustain it to 2050.

Clean electricity standard approach to net-zero electricity

Federal backstop carbon intensity performance ("clean electricity standard") at 37 g CO_2/kWh for any generating plants completed in 2025 or later. (Allows natural gas and perhaps coal, but only with CCS.)

Performance requirement for existing plants falls to 0 g CO_2/kWh by 2030 in provinces dominated by hydro-nuclear-wind and by 2035 in provinces still reliant on some coal or natural gas in 2020.

Provinces can negotiate equivalency agreements that include:

(1) negative emission technologies to counter residual emissions,

(2) total provincial system compliance instead of individual plant compliance, and

(3) multi-province compliance instead of individual province compliance, using intra- and interprovincial credit trading mechanisms for private and public generators.

3.3 Recognizing the limits of federal electricity policy

Our proposals for backstop federal carbon pricing or a clean electricity standard (or both) focus on the transition from provincial systems that currently differ in their carbon intensity to a growing zero-emission electricity system throughout Canada. We thus emphasize new and retrofit investment decisions by electricity generators and neglect the detailed design of system management and bidding systems that would facilitate economically efficient dispatch, between now and 2035, of generators of different carbon intensities and operating costs. These are the domain of provincial governments, and federal policy efforts will likely be viewed as jurisdictional intrusion.

This is the reason our report is silent on many other policy concerns of electricity system stakeholders, concerns that mostly fall in the domain of provincial policy. These unaddressed topics include centralized versus decentralized generation, the pros and cons of public versus private ownership, financing capacity investments, electricity affordability, electricity regulation and rate design, transition support for workers affected by the pursuit of zero-emission electricity, reliability of electricity generation and distribution as non-dispatchable renewables and electricity demand peaks increase, non-GHG environmental and social trade-offs of alternative zero-emission electricity options, cost-effective energy efficiency and load shifting, innovation and adoption in energy storage, reconciliation with Indigenous peoples, and special challenges of zero-emission electricity in remote and northern communities.

In these latter two cases, federal policies and financial contributions will, however, continue to be critically important. Indigenous communities are often northern and/or remote. And in many cases the transition to zero-emission electricity will be particularly costly given the technical and seasonal constraints for solar, wind, small hydro and bio-energy, as well as for energy storage and transmission. With its responsibility for achieving reconciliation with Indigenous Peoples and for supporting their aspirations for economic and political self-determination, the federal government must increase its efforts in this dimension of zero-emission electricity.

Aside from this critical area, however, the provinces will continue to have the greatest influence over the technological path that each follows in transitioning to and then expanding a zero-emission electricity system. In the next section, we illustrate possible technological paths that may result from federal zero-emission electricity policy. One path presents generation investments if provinces make decisions consistent with their recent resource preferences, namely continued use of fossil fuels in Alberta and Saskatchewan and continued development of large hydropower in the Atlantic provinces. The other path presents possible generation investments if the trend toward smaller-scale renewable resources continues. Our current estimate of the latter path is that it will be more expensive. But this estimate is highly uncertain, especially with the rapidly changing technologies for energy storage and load management, and recent experiences with cost overruns in large hydro and CCS investments. The relative costs of our two paths may well be the opposite of what we estimate here.

4 Generation evolution with federal backstop pricing or regulation

Canada’s electricity system can evolve to net-zero emissions under either a backstop-pricing or a backstop regulatory approach, and we have designed our two proposed policies to incentivize the same rate of GHG intensity decline such that the generation mix and resulting emissions would be similar. Thus, we can think of the pricing and regulatory policy approaches as creating the same incentives for the shift to zero-emission electricity.

The policy driver to zero-emission provincial electricity systems is the same. But the technological outcomes may differ depending on province-specific preferences. To illustrate the possibly diverse outcomes, we provide in this section results from simulating two technology pathways for each province to 2035. (In the appendix we provide outcomes also for northern territories.) In both zero-emission pathways, we assume that provinces will not allow substantial expansion of large hydro and nuclear power, meaning that wind, solar biomass and other renewables dominate generation growth. In both, we assume that the capacities of transmission grid interties between provinces will not be substantially increased, given past reluctance for expanded interdependence. And in both, we assume significant development of energy storage and load shifting to ensure reliable electricity systems as the contribution of non-dispatchable electricity from wind and solar increases.

The paths differ, however, because in the "status quo" technology path we assume that some provinces will develop zero-emission options that are currently seen as acceptable by their governments. These include the substantial use of natural gas with CCS (and some bioenergy with CCS) in Alberta and Saskatchewan and some development of large hydro, especially in the Atlantic provinces to take advantage of the new undersea transmission links.

In the other "environmentally constrained" technology path, we assume much less CCS (whether with natural gas or bioenergy) and no new large hydro developments anywhere in Canada. This latter path requires even more investment in wind, solar and energy storage than the status quo path.

We calculate the second path to be more expensive, but that result carries a great deal of uncertainty. Electricity cost estimates can change quickly, examples being the dramatic cost overruns of the coal plant CCS retrofit in Saskatchewan, and large hydro projects at Muskrat Falls in Labrador and Site C in B.C. In contrast, the installed costs of wind and solar have fallen dramatically over the past decade, and some experts predict a similar evolution over the next decade for costs of the extra energy storage they need to ensure system reliability.

4.1 Status quo technology path to zero-emissions in 2035

Our status quo policy simulation shows a zero-emission Canadian electricity system in 2035 comprising hydro, wind and a mix of flexible thermal generation in the form of nuclear, natural gas with CCS and biomass, as shown in Figure 5. PV capacity is installed in those provinces where solar conditions are particularly favourable. This new generation mix pairs non-dispatchable wind and solar with the dispatchable existing large hydro in several provinces and new efficient natural gas with CCS in Alberta and Saskatchewan where geological storage of CO_2 is a feasible option. Overall, new capacity is installed that is complementary to the legacy baseload assets in each province.

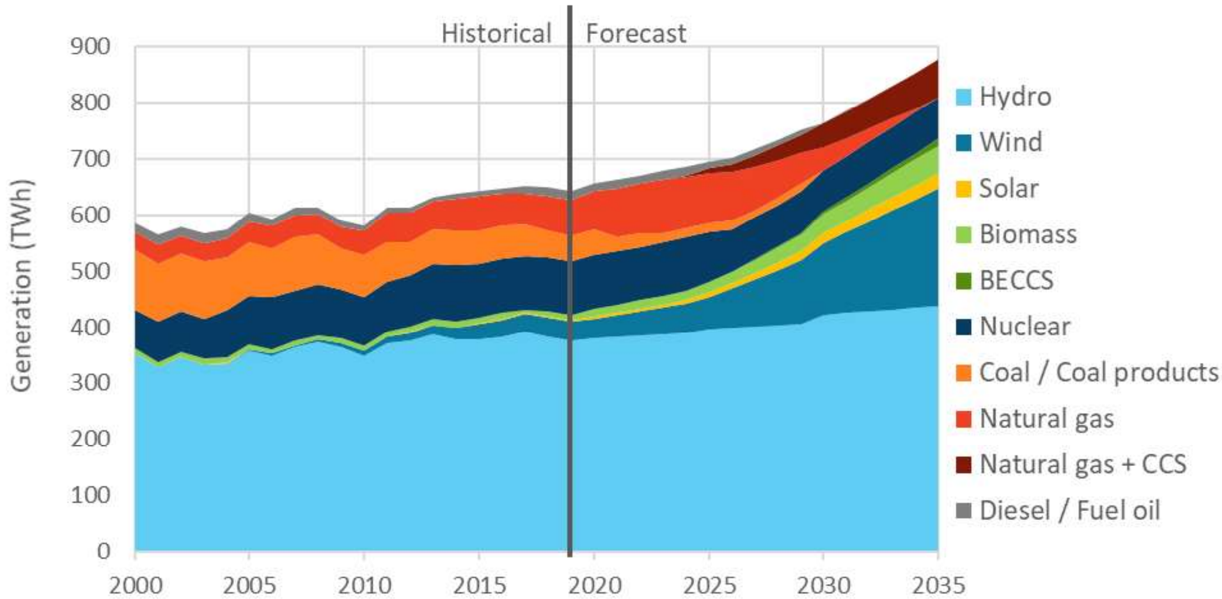

Figure 5: Canada electricity generation and GHG intensity: 2000-2035

Source: Statistics Canada (various tables); Authors' forecast

Our national-level results for 2035 are broadly in line with other net-zero studies, such as those of the Canadian Institute for Climate Choices and the Deep Decarbonization Pathways Project.[41] These studies forecast quickly growing generation from non-thermal renewables (large hydro, wind and solar) paired with non-emitting thermal generation (biomass, natural gas with CCS and coal with CCS). While it's harder to compare with some other net-zero studies that provide a global assessment, the scale and mix of installed renewables in our analysis is generally comparable to other decarbonization studies such as the 2021 global net-zero report from the International Energy Agency.[42] Again, the main conclusion of the IEA study is that non-emitting renewables must play a major role in a net-zero future, with flexible complementary options to provide grid stability and manage system costs. Figure 6 provides our forecast of provincial generation by source in 2035. Province-specific details of the policy impact in our analysis, including electricity capacity, generation and emissions, are included in Appendix B.

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[41] See section 1.1. for references.

[42] International Energy Agency. (2021). *Net Zero by 2050: A Roadmap for the Global Energy Sector.* https://www.iea.org/reports/net-zero-by-2050

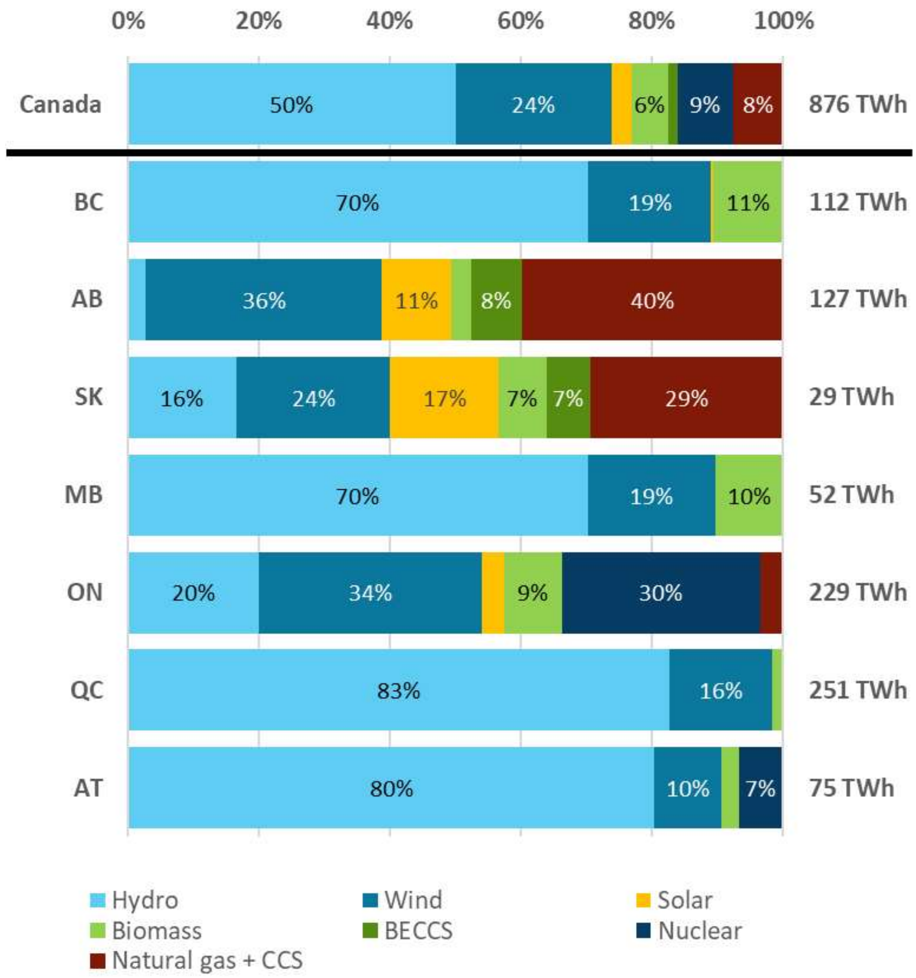

Figure 6: Best-guess electricity generation by region and type in 2035

Source: Authors' forecast

The most dramatic changes occur in the prairie provinces. Alberta and Saskatchewan see their electricity systems use increasing amounts of wind, solar and biomass. However, to provide dispatch flexibility, existing coal plants are converted to natural gas, then later retrofitted with CCS. And in some cases, new natural gas with CCS is built.[43] Net-zero policies incentivize both a decrease in the amount of natural gas used to generate electricity and a shift to using CCS to limit the emissions from fuel combustion. In our best-guess forecast, natural gas use peaks in 2026 and causes few emissions by 2035 with the complete use of CCS, as shown in Figure 7.

[43] We recognize that CCS technology, while it has been theoretically available for many years, is still in the early stages of development and commercialization in Canada. This means there may be the potential for unforeseen increases in cost or decreases in effectiveness over the longer term. We note, however, that in Alberta and Saskatchewan, there is widespread experience with industrial chemistry processes, pipelines and drilling technologies, which should aid in utilizing CCS.

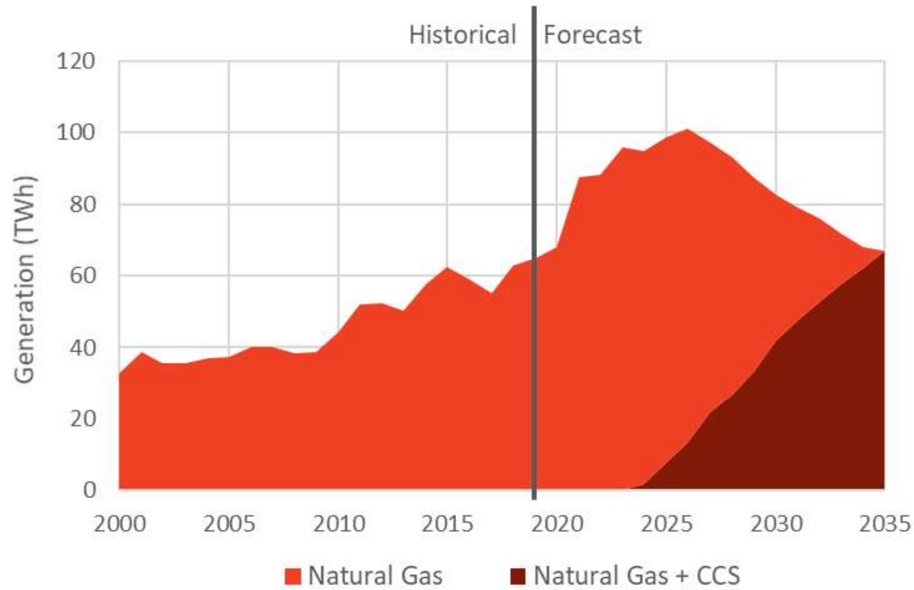

Figure 7: Canadian electricity generation from natural gas: 2000-2035

Source: Statistics Canada (various tables); Authors' forecast

Carbon capture technology removes most of the GHG emissions from these plants, but biomass combined with CCS (BECCS) is needed to provide negative emissions to offset what is still emitted. The potential of BECCS increases over time as carbon pricing or regulations increase in stringency. Not only do BECCS facilities earn revenue from electricity generated, but also from the carbon price for any CO_2 stored underground. This double incentive makes BECCS particularly attractive in Alberta and Saskatchewan, where there is abundant experience with drilling technologies and plentiful, high-quality geological storage capacity because of the Western Sedimentary Basin. Figure 8 shows that by 2035 Alberta and Saskatchewan could have net-negative emissions beyond what they need to offset natural gas plants in their own power systems, providing a revenue opportunity from offsetting emissions outside the electricity sector in their provinces or by trading this benefit with other provinces.

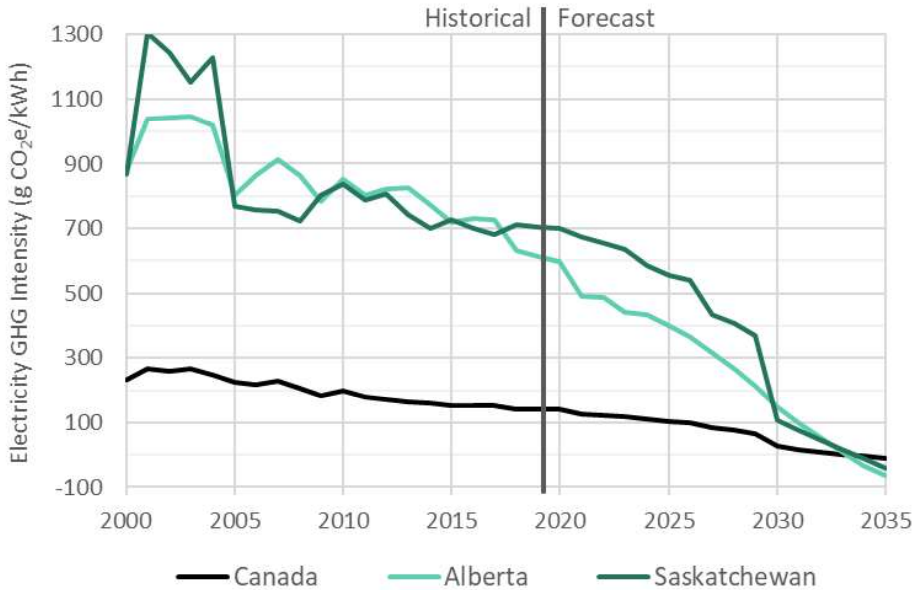

Figure 8: Canadian electricity GHG intensity: 2000-2035

Source: Statistics Canada (various tables); Authors' forecast

The Atlantic region will also experience a significant change in how electricity is generated in individual provinces, and in electricity trade between them. While Newfoundland and Labrador will continue to produce most of its power from hydro and P.E.I. will continue to invest in on-island wind, New Brunswick and Nova Scotia would see their thermal power plants replaced in part by hydropower imports from new supply agreements with Newfoundland and Labrador. While there is not an economic case today for the development of the proposed Gull Island hydro facility, the regional coordination in developing the Maritime Link (and potentially the expanded Atlantic Loop) could provide the demand needed to proceed with the project. This dispatchable hydro and its storage will complement increased development of onshore and offshore wind projects and solar PV.

Ontario will also see a significant change in its generation mix. The Pickering nuclear facility is to close by 2025, and with the total system growing this means that nuclear power's share of Ontario's generation falls to half its current percentage. Generation growth occurs via dramatic increases in wind, solar, biomass and some natural gas with CCS to help maintain system reliability. Use of this latter option is constrained, however, by the limited opportunities for low-cost underground storage in Ontario.

The hydro-dominated provinces of B.C., Quebec and Manitoba see substantial expansion of wind generation, which is supported by the plentiful dispatchable energy storage capacity of the hydro facilities. Some biomass-fired power is also added, especially in B.C. and Manitoba.

4.2 Environmentally constrained technology path

To account for possible environmental and economic risks associated with CCS and large hydro, we also present a technology path for the electricity system that constrains the reliance on these options. These restrictions are included because some technologies have not yet been widely used (natural gas with CCS, BECCS) or are associated with concerns about cost overruns and environmental and social impacts (Gull Island hydropower project).

To compensate for the technologies excluded in this simulation, we add or increase several options: demand-side management and load shifting, wind and solar backed up with short- and long-term storage to compensate for intermittency, and possibly hydrogen to replace natural gas combustion. We estimate higher costs for this environmentally constrained scenario, but given the substantial future cost uncertainties (in CCS, large hydro projects and energy storage), the eventual outcome might be reversed.

Our environmentally constrained policy simulation shows a system in 2035 comprising hydro, wind and solar, backed up with various storage options, and a mix of flexible thermal generation, primarily from nuclear and biomass. Figure 9 shows the evolution of all electricity generation in Canada. Large amounts of wind and solar PV are installed in those provinces where conditions are particularly favourable, especially southern Alberta and Saskatchewan. This new generation mix pairs non-dispatchable wind and solar with the dispatchable existing large hydro in several provinces and new storage options. Overall, new capacity is complementary to the legacy baseload assets in each province, while trying to maintain flexibility in the system and hedge against environmental risks.

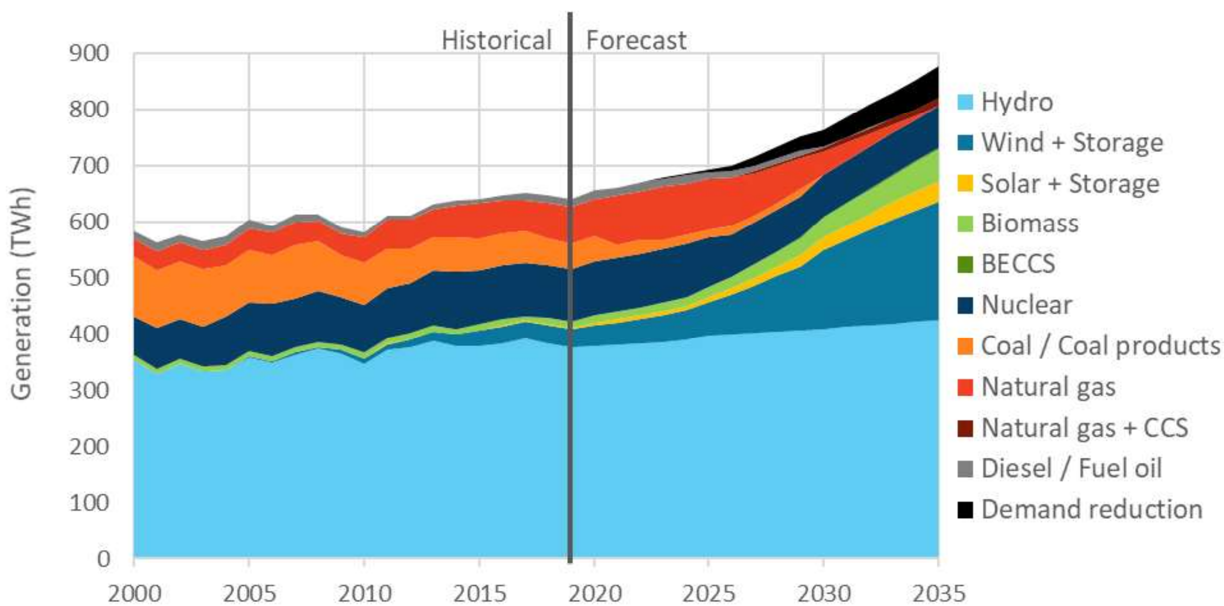

Figure 9: Canada electricity generation and GHG intensity: 2000-2035

Source: Statistics Canada (various tables); Authors' forecast

Batteries are an available option to meet short duration (<6 hour) storage needs. While battery costs are currently high compared to other storage options to provide dispatchable electricity, like many new technologies they could see considerable cost reductions with operational learning and additional research, deployment and mass production. Indeed, some solar and battery storage installations can already compete with single-cycle natural gas turbines to provide peak power reliability in some locations. However, expanded use of solar in Canada requires seasonal storage due to reduced output in winter. There are currently no commercially available technologies that can provide seasonal electricity storage and the estimated costs of various pre-commercial options are high compared to natural gas with CCS or biomass (with or without CCS) that can readily store energy throughout the year to produce dispatchable electricity when needed by peak demand and/or low output of wind and solar.

Our national-level results for 2035 are again broadly in line with other net-zero studies. The levels of intermittent renewables installed in some provinces reach the point where grid reliability and flexibility are critical factors to manage. Some studies, like the net-zero report from the Canadian Institute for Climate Choices, point out that lower levels of wind and solar, like that of Ontario in our forecast, can be managed with existing technologies, such as battery storage and demand response (resulting from flexible time-of-use pricing). However, much larger shares of wind and solar, like those in Alberta and Saskatchewan, will require rapid commercialization of what are today only prospective storage technologies.

Figure 10 provides our simulation of provincial generation by source in 2035. Province-specific details of the policy impact in our analysis, including electricity capacity, generation and emissions, are included in Appendix B.

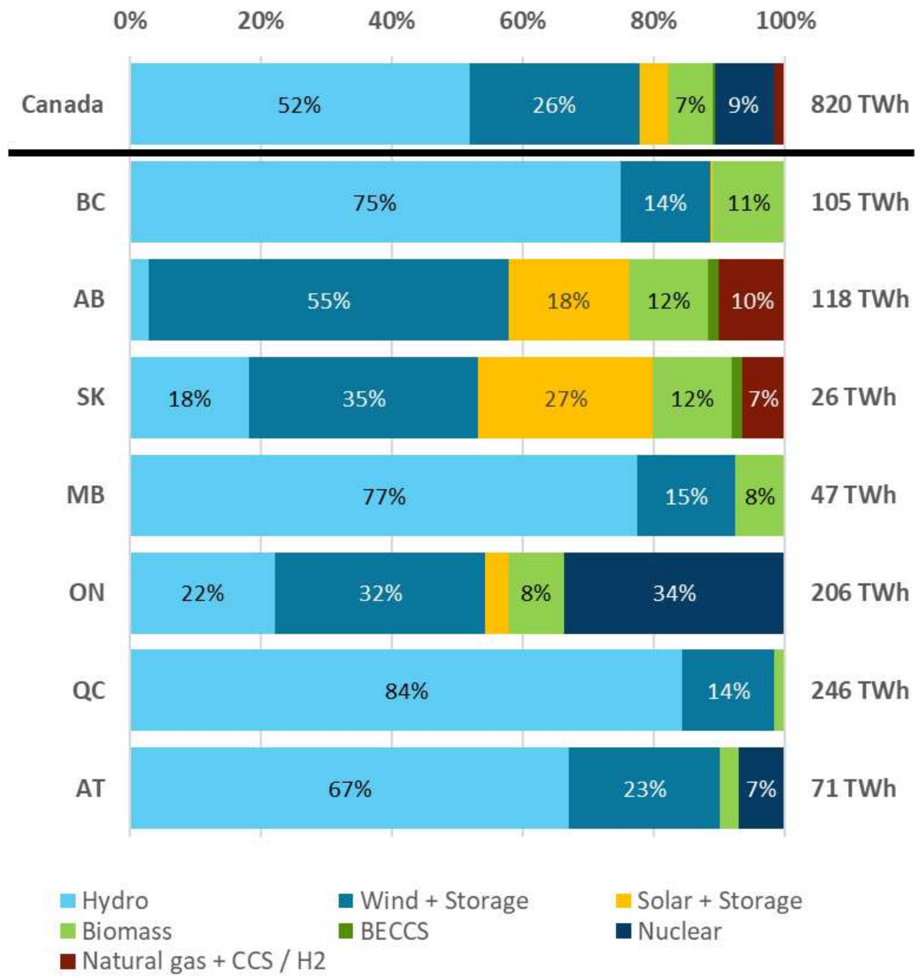

Figure 10: Electricity generation by region and type in 2035

Source: Authors' forecast

Again, Alberta and Saskatchewan see the most profound changes in their electricity systems. Wind and solar make up the majority of generation. Because storage and demand response provide the dispatch flexibility mechanisms, existing coal plants are decommissioned rather than converted to natural gas. This means that some coal plants that are currently being converted to natural gas, or were converted recently, would become stranded assets as the carbon price rises or the clean electricity standard decreases toward zero. Only a small amount of natural gas with CCS (or hydrogen) remains in our forecast as a low-cost flexibility option, as shown in Figure 11.

The future role in the power system of green hydrogen produced by electrolysis is uncertain. The amount of power generated from hydrogen could be much higher if the production cost decreases substantially or if low-cost electricity is available for electrolysis, perhaps because storage costs are high enough to not allow all intermittent renewable electricity to be dispatched when demand is high. Either of these outcomes could increase the amount of hydrogen from what we show in our environmentally constrained simulation.

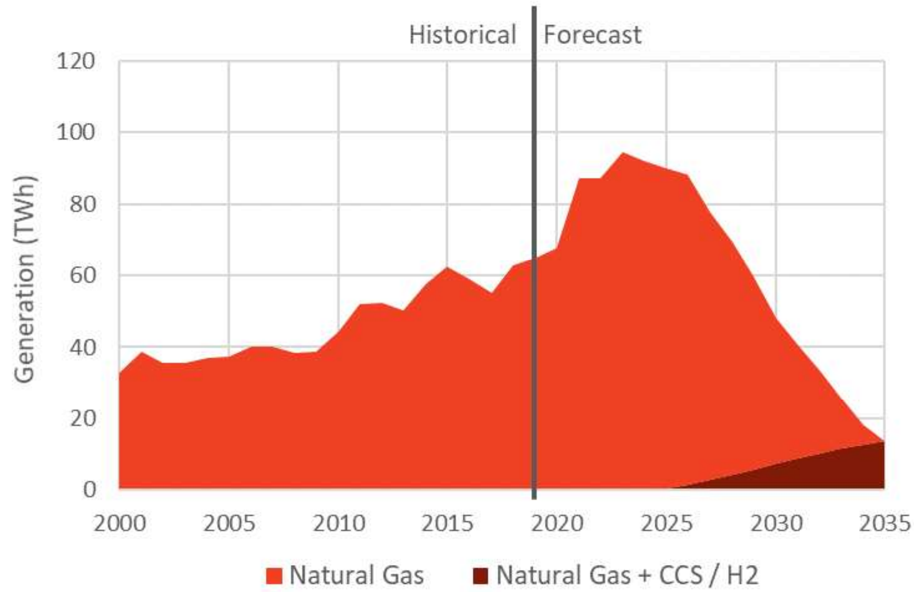

Figure 11: Canadian electricity generation from natural gas: 2000-2035

Source: Statistics Canada (various tables); Authors' forecast

In the Atlantic region, we exclude new large hydro projects in this simulation (specifically Gull Island). Newfoundland and Labrador continue to produce most power from hydro and provide flexible generation for the other Atlantic provinces through supply agreements. In this sense, the regional coordination of an expanded Atlantic Loop would still be valuable to provide dispatchable hydro to complement increased development of onshore and offshore wind projects and solar PV. Demand reduction and increased hydro utilization could help maintain reliability for a regional grid.

Since Ontario included less natural gas with CCS than some other provinces in our status quo scenario, the exclusion of this technology from this forecast has less impact. Because of the large amount of electricity generated in Ontario and the existing hydro and nuclear capacities, some of the excluded natural gas capacity is offset by demand reduction and load shifting.

Except for reduced generation needs due to demand side management actions, meaning that existing legacy generation plays a larger role in the future, the forecasts for the hydro-dominated provinces of B.C., Quebec and Manitoba are similar in both of our forecasts.

5 Conclusion

Like other countries, Canada has embraced the goal of reaching net-zero GHG emissions by 2050, and research shows that a low-cost path involves decarbonizing our electricity system, perhaps even achieving negative emissions in some locations via bioenergy with carbon capture and storage (BECCS). While most of Canada is currently blessed with low-emission electricity, some provinces are more reliant on GHG-emitting coal and natural gas plants, meaning that the costs of transitioning to zero-emission electricity are uneven across the country. This challenge for the net-zero objective must be addressed.

An additional challenge is that a net-zero energy system likely requires a doubling of electricity generation in just 30 years, and large hydro and nuclear power — which currently dominate Canada's electricity system — are unlikely to achieve significant expansion. Canada's plentiful reserves of coal and natural gas are available to provide decades of low-cost dispatchable power, but if these two options can only be used with carbon capture and storage (CCS), the cost of electricity to power transportation, heat buildings and run industry will be higher. Fortunately, Canada's geography provides favourable opportunities to develop wind and solar throughout the country, as well as region-specific biomass, small hydro, some geothermal and CO_2 storage sites for natural gas with CCS. But policies will be required to ensure that these options for zero-emission electricity dominate capacity growth over the next three decades.

Energy is under provincial jurisdiction in Canada, and provincial electricity systems are especially seen as the domain of provincial governments, with Crown electric utilities as the norm. Canada's courts, however, have recognized the federal government's authority to price carbon and regulate technologies, including in the electricity sector, to achieve national GHG targets. Starting with the Harper government in 2012, the federal government has regulated electricity plants for their carbon intensity, but it applies this policy, like its carbon pricing policy, as a backstop. This means that the federal government is willing to allow provinces to implement their own regulations or carbon pricing system in electricity (and other sectors) if these are approximately equivalent to its national policy. It is also willing to allow high-emitting jurisdictions some leeway in setting the initial stringency of their policies, although its ultimate goal is consistent national policy on the path to net-zero.

Current federal policy is not, however, on a path to net-zero electricity. In 2016, the Trudeau government changed the timeline of the original Harper regulation such that by 2030 all coal plants would either close, convert to natural gas or biomass, or add CCS. But the federal government's carbon intensity regulation under the Canadian Environmental Protection Act encourages switching these plants to natural gas and even construction of new natural gas plants. If one considers the dramatic growth ahead for electricity generation, Canada's aggregate electricity sector emissions may decline slightly for five years, as coal plants are closed or converted, but then rise quickly in the following years with increased natural gas generation. A zero-emission future requires either a zero-emission regulation or a very high carbon price applied to all GHG emissions of all electricity generators.

In this report, we propose a conversion of current carbon pricing policy in electricity or a federal clean electricity standard to ensure that a rapidly expanding national electricity system is zero-emission. While our focus is on new investments everywhere in the country, we support the federal government's flexibility in negotiating equivalency agreements with those individual provinces that are challenged by its current regulation, especially in the 2020-2030 time frame. Equivalency agreements should differentiate between provinces and avoid excessive intrusion into provincial jurisdiction, but they must also ensure that the short-term emissions impact of federal regulation is not undermined.

When it comes to long-term investments in new generation, the current federal carbon intensity regulation lacks the stringency necessary to prevent substantial development of natural gas generation that does not include CCS. To prevent this outcome, our proposed clean electricity standard, or equivalent carbon pricing policy, includes the following elements.

After 2025, investments in new natural gas, or coal conversion to natural gas, must include CCS. From 2030, all electricity generators located in British Columbia, Manitoba, Ontario, Quebec, Newfoundland and Labrador and Prince Edward Island must be zero-emission. From 2035, this requirement extends to all electricity generators in Alberta, Saskatchewan, New Brunswick and Nova Scotia. However, while the regulation applies initially to individual generating facilities, each province can negotiate an equivalency agreement to achieve the regulatory intent on average in its electricity system, as long as emissions from non-compliant units are compensated by negative emissions from other units. Thus, negative emissions from BECCS (or perhaps even direct air capture with CCS) can cancel out residual emissions from natural gas or coal plants with CCS.[44]

Finally, provinces are also encouraged to collaborate in negotiating an equivalency agreement in which two or more provinces are counted as one for the purpose of achieving net-zero emissions. This latter flexibility may help incentivize interprovincial cooperation, including expansion of grid interties and trading of negative emission credits. The benefits may be considerable because of the complementarity of neighbouring electricity systems, notably Alberta and B.C., Saskatchewan and Manitoba, Ontario and Quebec, and Quebec and the Atlantic provinces. Canada can achieve a zero-emission electricity system by 2035, an essential objective in succeeding with the climate change challenge.

[44] A Canadian example of a direct air capture technology is being developed by Carbon Engineering. https://carbonengineering.com

Appendix A: Territories electricity system details

Yukon generates most of its electricity from hydro sources, which account for 80 per cent of total generation. Diesel and natural gas are required for periods of peak demand and in remote communities. Yukon generated about 0.5 TWh of electricity in 2019. Yukon Energy Corporation, a Crown corporation, generates most of Yukon's electricity. Privately owned ATCO Electric Yukon also contributes some power generation. The Yukon Utilities Board regulates the two utility companies that operate in the territory.

Northwest Territories generates 33 per cent of electricity from hydroelectricity in normal precipitation years. In drier years, the territory relies on diesel to make up for the shortfall. Diesel is also the primary electricity source for remote communities not connected to one of the territory's two hydro-based grids. Smaller contributions come from natural gas, wind and solar. In 2019, total generation was 0.7 TWh. Northwest Territories Power Corporation generates most of the electricity in the territory, while Northland Utilities (privately owned joint partnership between ATCO and Denendeh Investments) also generates diesel power for distribution in remote communities. The Northwest Territories Public Utilities Board is an independent, quasi-judicial agency of the Government of the Northwest Territories responsible for regulating public utilities, including electricity.

Almost all of Nunavut's electricity is generated from diesel fuel imported during the summer and stored for year-round use. Approximately 55 million litres of diesel are consumed annually to generate electricity. Nunavut generated around 0.2 TWh of electricity in 2019. There are no regional or territorial electricity grids in Nunavut; all electricity generation is community-based. Qulliq Energy Corporation (QEC), owned by the Nunavut government, is responsible for generation, transmission and distribution of electricity in the territory. The minister responsible for the QEC, along with the executive council, make the final decisions on power rates.

Because of long distances to generation facilities in neighbouring provinces and territories, there are no transmission lines for trade of electricity in any of the territories.

Appendix B: Forecast Results

Capacity - Status Quo Path

Capacity (GW)	2000	2005	2010	2015	2020	2025	2030	2035
Canada								
Hydro	72.7	73.7	75.1	79.2	80.8	81.9	84.1	84.1
Wind	0.1	0.8	3.9	11.3	14.7	21.4	40.4	62.3
Solar	0.0	0.0	0.2	2.2	3.6	6.1	11.0	15.9
Biomass	2.2	2.3	4.2	2.7	3.3	3.9	8.0	12.4
No CCS	*2.2*	*2.3*	*4.2*	*2.7*	*3.3*	*3.9*	*7.0*	*9.8*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.1*	*0.9*	*2.6*
Nuclear	13.3	13.3	12.7	14.0	14.0	13.0	10.9	10.9
Coal / Coal products	19.3	16.7	14.1	9.6	7.4	2.5	0.0	0.0
Natural Gas	9.5	10.3	13.7	17.6	18.6	23.3	18.3	15.9
No CCS	*9.5*	*10.3*	*13.7*	*17.6*	*18.6*	*23.3*	*7.3*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*2.9*	*11.0*	*15.9*
Diesel / Fuel oil	14.3	17.8	6.8	5.9	5.9	5.1	0.1	0.0
Total	131.3	134.9	130.7	142.6	148.3	157.1	172.8	201.5

Capacity (GW)	2000	2005	2010	2015	2020	2025	2030	2035
British Columbia								
Hydro	13.3	13.4	13.2	14.4	15.4	16.5	16.5	16.5
Wind	0.0	0.0	0.1	0.5	0.7	0.9	2.9	6.4
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Biomass	0.7	0.7	0.9	0.9	0.9	1.1	1.6	2.1
No CCS	*0.7*	*0.7*	*0.9*	*0.9*	*0.9*	*1.1*	*1.6*	*2.1*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	2.0	1.4	1.4	0.6	0.6	0.0	0.0	0.0
No CCS	*2.0*	*1.4*	*1.4*	*0.6*	*0.6*	*0.0*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0
Total	16.2	15.7	15.6	16.5	17.7	18.5	21.0	25.2
Alberta								
Hydro	0.8	1.1	0.9	1.2	1.2	1.2	1.2	1.2
Wind	0.1	0.4	0.7	1.5	1.9	3.2	8.2	12.9
Solar	0.0	0.0	0.0	0.0	0.2	1.2	4.8	8.1
Biomass	0.2	0.3	0.3	0.4	0.7	0.7	1.4	2.8
No CCS	*0.2*	*0.3*	*0.3*	*0.4*	*0.7*	*0.7*	*0.7*	*0.7*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.1*	*2.2*
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	5.5	5.8	6.4	6.4	4.6	0.0	0.0	0.0
Natural Gas	3.5	4.6	5.0	6.3	6.6	11.8	11.1	9.7
No CCS	*3.5*	*4.6*	*5.0*	*6.3*	*6.6*	*11.8*	*6.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.7*	*5.2*	*9.7*
Diesel / Fuel oil	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Total	10.3	12.2	13.4	15.9	15.2	18.2	26.7	34.7
Saskatchewan								
Hydro	0.7	1.0	0.9	0.9	0.9	0.9	0.9	0.9
Wind	0.0	0.0	0.2	0.2	0.3	0.7	1.3	1.9
Solar	0.0	0.0	0.0	0.0	0.0	0.8	1.9	2.9
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.9
No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.2*	*0.5*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.2*	*0.5*
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	1.7	1.8	1.8	1.5	1.5	1.3	0.0	0.0
Natural Gas	0.9	0.9	1.3	1.5	2.2	2.6	3.1	2.2
No CCS	*0.9*	*0.9*	*1.3*	*1.5*	*2.2*	*2.6*	*1.3*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.2*	*1.8*	*2.2*
Diesel / Fuel oil	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	3.4	3.8	4.2	4.1	4.9	6.3	7.5	8.7
Manitoba								
Hydro	4.7	5.4	5.1	5.4	5.5	5.5	5.5	5.5
Wind	0.0	0.0	0.1	0.3	0.3	0.5	1.8	2.8
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.1	0.1	0.0	0.0	0.0	0.1	0.6	1.1
No CCS	*0.1*	*0.1*	*0.0*	*0.0*	*0.0*	*0.1*	*0.6*	*1.1*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Natural Gas	0.0	0.1	0.4	0.4	0.4	0.3	0.0	0.0
No CCS	*0.0*	*0.1*	*0.4*	*0.4*	*0.4*	*0.3*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	5.0	5.7	5.7	6.2	6.2	6.4	7.9	9.4

Capacity (GW)	2000	2005	2010	2015	2020	2025	2030	2035
Ontario								
Hydro	8.7	8.1	8.4	9.0	9.1	9.1	9.1	9.1
Wind	0.0	0.0	1.4	4.6	6.0	9.0	16.0	23.6
Solar	0.0	0.0	0.2	2.2	3.3	4.0	4.3	4.7
Biomass	0.5	0.6	2.3	0.8	1.0	1.3	3.0	4.3
No CCS	*0.5*	*0.6*	*2.3*	*0.8*	*1.0*	*1.3*	*3.0*	*4.3*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	12.0	12.0	12.0	13.3	13.3	12.3	10.2	10.2
Coal / Coal products	10.2	7.3	4.2	0.0	0.1	0.1	0.0	0.0
Natural Gas	2.9	2.6	4.3	7.6	7.4	7.3	4.0	4.0
No CCS	*2.9*	*2.6*	*4.3*	*7.6*	*7.4*	*7.3*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*2.0*	*4.0*	*4.0*
Diesel / Fuel oil	4.3	8.6	2.1	2.1	2.1	1.5	0.0	0.0
Total	38.5	39.3	34.9	39.6	42.4	44.7	46.7	55.9
Quebec								
Hydro	35.9	36.1	38.4	40.0	40.4	40.4	40.4	40.4
Wind	0.0	0.2	0.8	3.2	4.3	5.5	8.3	12.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.3	0.3	0.3	0.2	0.3	0.3	0.5	0.8
No CCS	*0.3*	*0.3*	*0.3*	*0.2*	*0.3*	*0.3*	*0.5*	*0.8*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	0.7	0.7	0.7	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	0.1	0.1	0.6	0.6	0.6	0.4	0.0	0.0
No CCS	*0.1*	*0.1*	*0.6*	*0.6*	*0.6*	*0.4*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	2.0	3.6	1.5	0.6	0.6	0.4	0.0	0.0
Total	39.1	41.0	42.3	44.6	46.2	47.1	49.2	53.2
Atlantic								
Hydro	8.3	8.4	8.1	8.1	8.1	8.1	10.3	10.3
Wind	0.0	0.0	0.6	1.1	1.3	1.6	1.9	2.4
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.5	0.4	0.4	0.4	0.3	0.3	0.4	0.4
No CCS	*0.5*	*0.4*	*0.4*	*0.4*	*0.3*	*0.3*	*0.4*	*0.4*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	0.7	0.7	0.0	0.7	0.7	0.7	0.7	0.7
Coal / Coal products	1.6	1.7	1.6	1.6	1.2	1.2	0.0	0.0
Natural Gas	0.0	0.4	0.8	0.6	0.8	0.8	0.0	0.0
No CCS	*0.0*	*0.4*	*0.8*	*0.6*	*0.8*	*0.8*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	7.4	5.2	2.8	2.8	2.8	2.8	0.0	0.0
Total	18.5	16.8	14.3	15.2	15.2	15.5	13.3	13.8
Territories								
Hydro	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Wind	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	0.2	0.1	0.2	0.2	0.2	0.2	0.1	0.0
Total	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4

Generation - Status Quo Path

		Generation (TWh)							
		2000	2005	2010	2015	2020	2025	2030	2035
Canada									
	Hydro	353.3	358.4	348.0	378.5	0.0	0.0	0.0	0.0
	Wind	0.2	1.6	8.6	26.7	0.0	0.0	0.0	0.0
	Solar	0.0	0.0	0.1	1.4	0.0	0.0	0.0	0.0
	Biomass	8.7	8.7	10.5	10.0	0.0	0.0	0.0	0.0
	No CCS	*8.7*	*8.7*	*10.5*	*10.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	68.7	86.8	85.5	96.0	0.0	0.0	0.0	0.0
	Coal / Coal products	106.8	94.7	74.7	58.3	0.0	0.0	0.0	0.0
	Natural Gas	32.3	37.7	44.3	62.2	0.0	0.0	0.0	0.0
	No CCS	*32.3*	*37.7*	*44.3*	*62.2*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	14.3	16.5	8.9	8.5	0.0	0.0	0.0	0.0
	Total	584.3	604.4	580.6	641.7	0.0	0.0	0.0	0.0

		Generation (TWh)							
		2000	2005	2010	2015	2020	2025	2030	2035
British Columbia									
	Hydro	59.8	60.3	54.2	65.0	0.0	0.0	0.0	0.0
	Wind	0.0	0.0	0.1	0.9	0.0	0.0	0.0	0.0
	Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Biomass	3.8	4.0	5.7	4.4	0.0	0.0	0.0	0.0
	No CCS	*3.8*	*4.0*	*5.7*	*4.4*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Natural Gas	3.9	3.4	2.3	1.1	0.0	0.0	0.0	0.0
	No CCS	*3.9*	*3.4*	*2.3*	*1.1*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.2	0.2	0.6	0.5	0.0	0.0	0.0	0.0
	Total	67.5	68.0	62.9	71.8	0.0	0.0	0.0	0.0
Alberta									
	Hydro	1.7	2.2	1.5	2.0	0.0	0.0	0.0	0.0
	Wind	0.1	0.8	1.6	4.1	0.0	0.0	0.0	0.0
	Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Biomass	1.0	1.5	1.4	2.0	0.0	0.0	0.0	0.0
	No CCS	*1.0*	*1.5*	*1.4*	*2.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	40.7	42.2	41.0	39.1	0.0	0.0	0.0	0.0
	Natural Gas	13.0	17.6	18.2	32.4	0.0	0.0	0.0	0.0
	No CCS	*13.0*	*17.6*	*18.2*	*32.4*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	3.0	1.7	2.5	1.6	0.0	0.0	0.0	0.0
	Total	59.6	66.1	66.2	81.2	0.0	0.0	0.0	0.0
Saskatchewan									
	Hydro	3.0	4.6	3.9	3.4	0.0	0.0	0.0	0.0
	Wind	0.0	0.1	0.5	0.6	0.0	0.0	0.0	0.0
	Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	11.4	12.2	12.1	12.1	0.0	0.0	0.0	0.0
	Natural Gas	2.9	2.9	3.3	7.3	0.0	0.0	0.0	0.0
	No CCS	*2.9*	*2.9*	*3.3*	*7.3*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total	17.4	19.8	19.8	23.4	0.0	0.0	0.0	0.0
Manitoba									
	Hydro	31.5	36.4	33.3	34.8	0.0	0.0	0.0	0.0
	Wind	0.0	0.1	0.3	0.9	0.0	0.0	0.0	0.0
	Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Biomass	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0
	No CCS	*0.1*	*0.1*	*0.0*	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	0.9	0.4	0.0	0.1	0.0	0.0	0.0	0.0
	Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
	Total	32.5	37.0	33.8	35.9	0.0	0.0	0.0	0.0

		Generation (TWh)							
		2000	2005	2010	2015	2020	2025	2030	2035
Ontario									
	Hydro	37.9	35.5	32.6	35.0	0.0	0.0	0.0	0.0
	Wind	0.0	0.0	3.1	11.4	0.0	0.0	0.0	0.0
	Solar	0.0	0.0	0.1	1.4	0.0	0.0	0.0	0.0
	Biomass	1.5	1.2	1.0	1.3	0.0	0.0	0.0	0.0
	No CCS	*1.5*	*1.2*	*1.0*	*1.3*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	59.8	78.0	82.0	91.8	0.0	0.0	0.0	0.0
	Coal / Coal products	41.2	30.0	12.5	0.4	0.0	0.0	0.0	0.0
	Natural Gas	12.0	10.9	15.7	17.4	0.0	0.0	0.0	0.0
	No CCS	*12.0*	*10.9*	*15.7*	*17.4*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.5	0.8	0.3	0.1	0.0	0.0	0.0	0.0
	Total	152.9	156.5	147.2	158.9	0.0	0.0	0.0	0.0
Quebec									
	Hydro	172.9	173.4	177.4	194.4	0.0	0.0	0.0	0.0
	Wind	0.1	0.4	1.5	6.4	0.0	0.0	0.0	0.0
	Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Biomass	1.1	0.8	1.2	1.3	0.0	0.0	0.0	0.0
	No CCS	*1.1*	*0.8*	*1.2*	*1.3*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	4.9	4.5	3.6	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	0.0	0.2	0.2	0.1	0.0	0.0	0.0	0.0
	Natural Gas	0.2	0.3	0.3	0.1	0.0	0.0	0.0	0.0
	No CCS	*0.2*	*0.3*	*0.3*	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.4	0.7	0.4	0.4	0.0	0.0	0.0	0.0
	Total	179.5	180.2	184.6	202.6	0.0	0.0	0.0	0.0
Atlantic									
	Hydro	45.9	45.4	44.6	43.3	0.0	0.0	0.0	0.0
	Wind	0.0	0.1	1.4	2.4	0.0	0.0	0.0	0.0
	Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Biomass	1.3	1.1	1.1	0.9	0.0	0.0	0.0	0.0
	No CCS	*1.3*	*1.1*	*1.1*	*0.9*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	4.0	4.4	0.0	4.3	0.0	0.0	0.0	0.0
	Coal / Coal products	12.7	9.7	8.9	6.5	0.0	0.0	0.0	0.0
	Natural Gas	0.3	2.4	4.4	3.9	0.0	0.0	0.0	0.0
	No CCS	*0.3*	*2.4*	*4.4*	*3.9*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	9.8	12.7	4.4	5.3	0.0	0.0	0.0	0.0
	Total	73.9	75.8	64.8	66.6	0.0	0.0	0.0	0.0
Territories									
	Hydro	0.6	0.6	0.6	0.6	0.0	0.0	0.0	0.0
	Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Natural Gas	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0
	No CCS	*0.1*	*0.1*	*0.1*	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.4	0.4	0.5	0.6	0.0	0.0	0.0	0.0
	Total	1.0	1.1	1.3	1.3	0.0	0.0	0.0	0.0

GHG Emissions - Status Quo Path

		GHG Emissions (Mt CO_2e)							
		2000	2005	2010	2015	2020	2025	2030	2035
Canada									
	Hydro								
	Wind								
	Solar								
	Biomass	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0
	No CCS	*0.1*	*0.1*	*0.1*	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	108.8	101.2	81.7	58.2	0.0	0.0	0.0	0.0
	Natural Gas	17.3	19.0	26.5	33.4	0.0	0.0	0.0	0.0
	No CCS	*17.3*	*19.0*	*26.5*	*33.4*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	10.4	14.5	7.2	6.8	0.0	0.0	0.0	0.0
	Total	136.6	134.8	115.5	98.5	0.0	0.0	0.0	0.0

		GHG Emissions (Mt CO_2e)							
		2000	2005	2010	2015	2020	2025	2030	2035
British Columbia									
	Hydro								
	Wind								
	Solar								
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Natural Gas	2.5	2.0	1.5	0.9	0.0	0.0	0.0	0.0
	No CCS	*2.5*	*2.0*	*1.5*	*0.9*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.1	0.1	0.4	0.3	0.0	0.0	0.0	0.0
	Total	2.6	2.2	1.9	1.3	0.0	0.0	0.0	0.0
Alberta									
	Hydro								
	Wind								
	Solar								
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	43.9	43.9	43.3	39.1	0.0	0.0	0.0	0.0
	Natural Gas	7.2	8.2	11.7	18.4	0.0	0.0	0.0	0.0
	No CCS	*7.2*	*8.2*	*11.7*	*18.4*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	1.1	0.9	1.3	0.7	0.0	0.0	0.0	0.0
	Total	52.3	53.0	56.3	58.3	0.0	0.0	0.0	0.0
Saskatchewan									
	Hydro								
	Wind								
	Solar								
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	13.4	13.6	14.2	12.9	0.0	0.0	0.0	0.0
	Natural Gas	1.6	1.6	2.4	4.2	0.0	0.0	0.0	0.0
	No CCS	*1.6*	*1.6*	*2.4*	*4.2*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total	15.0	15.2	16.6	17.1	0.0	0.0	0.0	0.0
Manitoba									
	Hydro								
	Wind								
	Solar								
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	1.0	0.6	0.1	0.1	0.0	0.0	0.0	0.0
	Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
	Total	1.1	0.6	0.1	0.1	0.0	0.0	0.0	0.0

		GHG Emissions (Mt CO_2e)							
		2000	2005	2010	2015	2020	2025	2030	2035
Ontario									
	Hydro								
	Wind								
	Solar								
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	39.2	33.4	15.2	0.1	0.0	0.0	0.0	0.0
	Natural Gas	5.7	5.5	8.2	7.8	0.0	0.0	0.0	0.0
	No CCS	*5.7*	*5.5*	*8.2*	*7.8*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.4	0.7	0.3	0.1	0.0	0.0	0.0	0.0
	Total	45.4	39.7	23.7	8.1	0.0	0.0	0.0	0.0
Quebec									
	Hydro								
	Wind								
	Solar								
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0
	Natural Gas	0.1	0.2	0.2	0.1	0.0	0.0	0.0	0.0
	No CCS	*0.1*	*0.2*	*0.2*	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.4	0.6	0.3	0.2	0.0	0.0	0.0	0.0
	Total	0.5	0.9	0.6	0.4	0.0	0.0	0.0	0.0
Atlantic									
	Hydro								
	Wind								
	Solar								
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	11.2	9.5	8.9	5.9	0.0	0.0	0.0	0.0
	Natural Gas	0.1	1.4	2.5	1.9	0.0	0.0	0.0	0.0
	No CCS	*0.1*	*1.4*	*2.5*	*1.9*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	8.0	11.9	4.5	5.0	0.0	0.0	0.0	0.0
	Total	19.3	22.8	15.9	12.8	0.0	0.0	0.0	0.0
Territories									
	Hydro								
	Wind								
	Solar								
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Natural Gas	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.1*	*0.1*	*0.1*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.3	0.3	0.4	0.5	0.0	0.0	0.0	0.0
	Total	0.4	0.4	0.5	0.5	0.0	0.0	0.0	0.0

Capacity - Environmentally Constrained Path

	Capacity (GW) 2000	2005	2010	2015	2020	2025	2030	2035
Canada								
Hydro	72.7	73.7	75.1	79.2	80.8	81.9	81.9	81.9
Wind	0.1	0.8	3.9	11.3	14.7	21.8	44.4	62.9
Solar	0.0	0.0	0.2	2.2	3.6	6.6	14.7	21.8
Biomass	2.2	2.3	4.2	2.7	3.3	3.8	7.5	11.6
No CCS	*2.2*	*2.3*	*4.2*	*2.7*	*3.3*	*3.8*	*7.3*	*11.1*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.2*	*0.5*
Nuclear	13.3	13.3	12.7	14.0	14.0	13.0	10.9	10.9
Coal / Coal products	19.3	16.7	14.1	9.6	7.4	2.5	0.0	0.0
Natural Gas	9.5	10.3	13.7	17.6	18.6	20.5	8.8	2.7
No CCS	*9.5*	*10.3*	*13.7*	*17.6*	*18.6*	*20.5*	*7.3*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.1*	*1.5*	*2.7*
Diesel / Fuel oil	14.3	17.8	6.8	5.9	5.9	5.1	0.1	0.0
Total	131.3	134.9	130.7	142.6	148.3	155.1	168.4	191.9

	Capacity (GW) 2000	2005	2010	2015	2020	2025	2030	2035
British Columbia								
Hydro	13.3	13.4	13.2	14.4	15.4	16.5	16.5	16.5
Wind	0.0	0.0	0.1	0.5	0.7	0.9	2.4	4.4
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Biomass	0.7	0.7	0.9	0.9	0.9	1.1	1.6	2.0
No CCS	*0.7*	*0.7*	*0.9*	*0.9*	*0.9*	*1.1*	*1.6*	*2.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	2.0	1.4	1.4	0.6	0.6	0.0	0.0	0.0
No CCS	*2.0*	*1.4*	*1.4*	*0.6*	*0.6*	*0.0*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0
Total	16.2	15.7	15.6	16.5	17.7	18.5	20.5	23.2
Alberta								
Hydro	0.8	1.1	0.9	1.2	1.2	1.2	1.2	1.2
Wind	0.1	0.4	0.7	1.5	1.9	3.7	11.4	18.4
Solar	0.0	0.0	0.0	0.0	0.2	1.7	7.5	12.9
Biomass	0.2	0.3	0.3	0.4	0.7	0.7	1.5	3.2
No CCS	*0.2*	*0.3*	*0.3*	*0.4*	*0.7*	*0.7*	*1.4*	*2.8*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.1*	*0.4*
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	5.5	5.8	6.4	6.4	4.6	0.0	0.0	0.0
Natural Gas	3.5	4.6	5.0	6.3	6.6	11.1	7.1	2.3
No CCS	*3.5*	*4.6*	*5.0*	*6.3*	*6.6*	*11.1*	*6.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.1*	*1.2*	*2.3*
Diesel / Fuel oil	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Total	10.3	12.2	13.4	15.9	15.2	18.5	28.9	38.0
Saskatchewan								
Hydro	0.7	1.0	0.9	0.9	0.9	0.9	0.9	0.9
Wind	0.0	0.0	0.2	0.2	0.3	0.7	1.8	2.5
Solar	0.0	0.0	0.0	0.0	0.0	0.8	3.0	4.2
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.8
No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.3*	*0.7*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.1*
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	1.7	1.8	1.8	1.5	1.5	1.3	0.0	0.0
Natural Gas	0.9	0.9	1.3	1.5	2.2	2.5	1.7	0.5
No CCS	*0.9*	*0.9*	*1.3*	*1.5*	*2.2*	*2.5*	*1.3*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.1*	*0.4*	*0.5*
Diesel / Fuel oil	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	3.4	3.8	4.2	4.1	4.9	6.2	7.7	8.8
Manitoba								
Hydro	4.7	5.4	5.1	5.4	5.5	5.5	5.5	5.5
Wind	0.0	0.0	0.1	0.3	0.3	0.4	1.2	2.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.1	0.1	0.0	0.0	0.0	0.1	0.4	0.8
No CCS	*0.1*	*0.1*	*0.0*	*0.0*	*0.0*	*0.1*	*0.4*	*0.8*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0
Natural Gas	0.0	0.1	0.4	0.4	0.4	0.3	0.0	0.0
No CCS	*0.0*	*0.1*	*0.4*	*0.4*	*0.4*	*0.3*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	5.0	5.7	5.7	6.2	6.2	6.3	7.1	8.2

	Capacity (GW) 2000	2005	2010	2015	2020	2025	2030	2035
Ontario								
Hydro	8.7	8.1	8.4	9.0	9.1	9.1	9.1	9.1
Wind	0.0	0.0	1.4	4.6	6.0	9.0	14.4	20.0
Solar	0.0	0.0	0.2	2.2	3.3	4.0	4.2	4.4
Biomass	0.5	0.6	2.3	0.8	1.0	1.2	2.7	3.7
No CCS	*0.5*	*0.6*	*2.3*	*0.8*	*1.0*	*1.2*	*2.7*	*3.7*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	12.0	12.0	12.0	13.3	13.3	12.3	10.2	10.2
Coal / Coal products	10.2	7.3	4.2	0.0	0.1	0.1	0.0	0.0
Natural Gas	2.9	2.6	4.3	7.6	7.4	5.3	0.0	0.0
No CCS	*2.9*	*2.6*	*4.3*	*7.6*	*7.4*	*5.3*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	4.3	8.6	2.1	2.1	2.1	1.5	0.0	0.0
Total	38.5	39.3	34.9	39.6	42.4	42.6	40.7	47.5
Quebec								
Hydro	35.9	36.1	38.4	40.0	40.4	40.4	40.4	40.4
Wind	0.0	0.2	0.8	3.2	4.3	5.5	8.3	10.5
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.3	0.3	0.3	0.2	0.3	0.3	0.5	0.8
No CCS	*0.3*	*0.3*	*0.3*	*0.2*	*0.3*	*0.3*	*0.5*	*0.8*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	0.7	0.7	0.7	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	0.1	0.1	0.6	0.6	0.6	0.4	0.0	0.0
No CCS	*0.1*	*0.1*	*0.6*	*0.6*	*0.6*	*0.4*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	2.0	3.6	1.5	0.6	0.6	0.4	0.0	0.0
Total	39.1	41.0	42.3	44.6	46.2	47.1	49.2	51.7
Atlantic								
Hydro	8.3	8.4	8.1	8.1	8.1	8.1	8.1	8.1
Wind	0.0	0.0	0.6	1.1	1.3	1.6	4.8	4.9
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.5	0.4	0.4	0.4	0.3	0.3	0.4	0.4
No CCS	*0.5*	*0.4*	*0.4*	*0.4*	*0.3*	*0.3*	*0.4*	*0.4*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	0.7	0.7	0.0	0.7	0.7	0.7	0.7	0.7
Coal / Coal products	1.6	1.7	1.6	1.6	1.2	1.2	0.0	0.0
Natural Gas	0.0	0.4	0.8	0.6	0.8	0.8	0.0	0.0
No CCS	*0.0*	*0.4*	*0.8*	*0.6*	*0.8*	*0.8*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	7.4	5.2	2.8	2.8	2.8	2.8	0.0	0.0
Total	18.5	16.8	14.3	15.2	15.2	15.5	14.0	14.1
Territories								
Hydro	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	0.2	0.1	0.2	0.2	0.2	0.2	0.1	0.0
Total	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4

Generation - Environmentally Constrained Path

	Generation (TWh) 2000	2005	2010	2015	2020	2025	2030	2035
Canada								
Hydro	353.3	358.4	348.0	378.5	379.3	396.0	408.8	424.6
Wind	0.2	1.6	8.6	26.7	35.6	60.6	141.1	212.5
Solar	0.0	0.0	0.1	1.4	4.3	9.2	23.2	36.2
Biomass	8.7	8.7	10.5	10.0	14.0	17.4	36.3	58.6
No CCS	*8.7*	*8.7*	*10.5*	*10.0*	*14.0*	*17.4*	*35.5*	*56.2*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.8*	*2.4*
Nuclear	68.7	86.8	85.5	96.0	95.5	88.5	74.5	74.5
Coal / Coal products	106.8	94.7	74.7	58.3	45.0	15.3	0.0	0.0
Natural Gas	32.3	37.7	44.3	62.2	67.7	90.1	48.1	13.7
No CCS	*32.3*	*37.7*	*44.3*	*62.2*	*67.7*	*90.1*	*40.7*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.5*	*7.5*	*13.7*
Diesel / Fuel oil	14.3	16.5	8.9	8.5	14.9	11.3	1.2	0.0
Total	584.3	604.4	580.6	641.7	656.2	688.3	733.2	820.1

	Generation (TWh) 2000	2005	2010	2015	2020	2025	2030	2035
British Columbia								
Hydro	59.8	60.3	54.2	65.0	57.4	68.1	74.9	78.4
Wind	0.0	0.0	0.1	0.9	1.7	2.4	7.3	14.4
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Biomass	3.8	4.0	5.7	4.4	4.5	5.7	8.9	11.6
No CCS	*3.8*	*4.0*	*5.7*	*4.4*	*4.5*	*5.7*	*8.9*	*11.6*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	3.9	3.4	2.3	1.1	1.9	0.0	0.0	0.0
No CCS	*3.9*	*3.4*	*2.3*	*1.1*	*1.9*	*0.0*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	0.2	0.2	0.6	0.5	0.7	0.7	0.0	0.0
Total	67.5	68.0	62.9	71.8	66.2	76.8	91.1	104.7
Alberta								
Hydro	1.7	2.2	1.5	2.0	2.1	2.7	3.2	3.5
Wind	0.1	0.8	1.6	4.1	4.9	11.1	38.8	64.7
Solar	0.0	0.0	0.0	0.0	0.3	2.3	11.9	21.5
Biomass	1.0	1.5	1.4	2.0	3.0	3.5	7.4	16.2
No CCS	*1.0*	*1.5*	*1.4*	*2.0*	*3.0*	*3.5*	*6.8*	*14.2*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.6*	*2.0*
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	40.7	42.2	41.0	39.1	27.7	0.0	0.0	0.0
Natural Gas	13.0	17.6	18.2	32.4	38.9	64.8	41.0	12.0
No CCS	*13.0*	*17.6*	*18.2*	*32.4*	*38.9*	*64.8*	*34.9*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.3*	*6.1*	*12.0*
Diesel / Fuel oil	3.0	1.7	2.5	1.6	9.3	5.6	1.0	0.0
Total	59.6	66.1	66.2	81.2	86.2	90.1	103.1	117.9
Saskatchewan								
Hydro	3.0	4.6	3.9	3.4	3.7	4.2	4.6	4.7
Wind	0.0	0.1	0.5	0.6	0.8	2.3	6.3	9.1
Solar	0.0	0.0	0.0	0.0	0.0	1.2	4.7	6.9
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	1.5	3.6
No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*1.3*	*3.2*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.2*	*0.4*
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	11.4	12.2	12.1	12.1	10.0	8.2	0.0	0.0
Natural Gas	2.9	2.9	3.3	7.3	9.6	10.8	7.1	1.7
No CCS	*2.9*	*2.9*	*3.3*	*7.3*	*9.6*	*10.8*	*5.8*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.2*	*1.3*	*1.7*
Diesel / Fuel oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	17.4	19.8	19.8	23.4	24.2	26.7	24.1	26.1
Manitoba								
Hydro	31.5	36.4	33.3	34.8	33.2	34.5	35.9	36.5
Wind	0.0	0.1	0.3	0.9	0.9	1.4	4.1	7.1
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.1	0.1	0.0	0.1	0.1	0.4	1.9	3.6
No CCS	*0.1*	*0.1*	*0.0*	*0.1*	*0.1*	*0.4*	*1.9*	*3.6*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	0.9	0.4	0.0	0.1	0.0	0.0	0.0	0.0
Natural Gas	0.0	0.0	0.0	0.0	1.2	0.7	0.0	0.0
No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*1.2*	*0.7*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
Total	32.5	37.0	33.8	35.9	35.4	37.1	41.8	47.1

	Generation (TWh) 2000	2005	2010	2015	2020	2025	2030	2035
Ontario								
Hydro	37.9	35.5	32.6	35.0	36.9	40.3	43.7	45.7
Wind	0.0	0.0	3.1	11.4	12.5	23.2	44.1	65.8
Solar	0.0	0.0	0.1	1.4	4.0	5.6	6.7	7.4
Biomass	1.5	1.2	1.0	1.3	3.5	4.7	11.9	17.5
No CCS	*1.5*	*1.2*	*1.0*	*1.3*	*3.5*	*4.7*	*11.9*	*17.5*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	59.8	78.0	82.0	91.8	90.5	83.5	69.5	69.5
Coal / Coal products	41.2	30.0	12.5	0.4	0.4	0.2	0.0	0.0
Natural Gas	12.0	10.9	15.7	17.4	11.6	9.9	0.0	0.0
No CCS	*12.0*	*10.9*	*15.7*	*17.4*	*11.6*	*9.9*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	0.5	0.8	0.3	0.1	0.2	0.6	0.0	0.0
Total	152.9	156.5	147.2	158.9	159.6	168.0	175.9	205.8
Quebec								
Hydro	172.9	173.4	177.4	194.4	199.5	199.4	199.3	207.8
Wind	0.1	0.4	1.5	6.4	11.7	15.9	25.3	34.5
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	1.1	0.8	1.2	1.3	1.5	1.6	2.8	4.1
No CCS	*1.1*	*0.8*	*1.2*	*1.3*	*1.5*	*1.6*	*2.8*	*4.1*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	4.9	4.5	3.6	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	0.0	0.2	0.2	0.1	0.0	0.0	0.0	0.0
Natural Gas	0.2	0.3	0.3	0.1	1.7	1.2	0.0	0.0
No CCS	*0.2*	*0.3*	*0.3*	*0.1*	*1.7*	*1.2*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	0.4	0.7	0.4	0.4	0.5	0.4	0.0	0.0
Total	179.5	180.2	184.6	202.6	215.0	218.5	227.4	246.4
Atlantic								
Hydro	45.9	45.4	44.6	43.3	45.8	46.1	46.4	47.3
Wind	0.0	0.1	1.4	2.4	3.0	4.2	14.8	16.2
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	1.3	1.1	1.1	0.9	1.4	1.5	1.9	2.1
No CCS	*1.3*	*1.1*	*1.1*	*0.9*	*1.4*	*1.5*	*1.9*	*2.1*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	4.0	4.4	0.0	4.3	5.0	5.0	5.0	5.0
Coal / Coal products	12.7	9.7	8.9	6.5	6.8	6.8	0.0	0.0
Natural Gas	0.3	2.4	4.4	3.9	2.5	2.5	0.0	0.0
No CCS	*0.3*	*2.4*	*4.4*	*3.9*	*2.5*	*2.5*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	9.8	12.7	4.4	5.3	3.6	3.6	0.0	0.0
Total	73.9	75.8	64.8	66.6	68.2	69.7	68.2	70.6
Territories								
Hydro	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.8
Wind	0.0	0.0	0.0	0.0	0.0	0.1	0.4	0.8
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal / Coal products	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
No CCS	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.1*	*0.0*
CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Diesel / Fuel oil	0.4	0.4	0.5	0.6	0.6	0.5	0.2	0.0
Total	1.0	1.1	1.3	1.3	1.4	1.4	1.5	1.5

GHG Emissions - Environmentally Constrained Path

		GHG Emissions (Mt CO_2e)							
		2000	2005	2010	2015	2020	2025	2030	2035
Canada									
	Hydro								
	Wind								
	Solar								
	Biomass	0.1	0.1	0.1	0.1	0.0	-0.1	-0.9	-2.4
	No CCS	*0.1*	*0.1*	*0.1*	*0.1*	*0.0*	*-0.1*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*-0.1*	*-0.9*	*-2.4*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	108.8	101.2	81.7	58.2	43.5	16.2	0.0	0.0
	Natural Gas	17.3	19.0	26.5	33.4	37.9	47.0	21.7	0.7
	No CCS	*17.3*	*19.0*	*26.5*	*33.4*	*37.9*	*47.0*	*21.3*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.4*	*0.7*
	Diesel / Fuel oil	10.4	14.5	7.2	6.8	10.7	8.6	0.6	0.0
	Total	136.6	134.8	115.5	98.5	92.0	71.9	21.4	-1.7

		GHG Emissions (Mt CO_2e)							
		2000	2005	2010	2015	2020	2025	2030	2035
British Columbia									
	Hydro								
	Wind								
	Solar								
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Natural Gas	2.5	2.0	1.5	0.9	1.7	0.0	0.0	0.0
	No CCS	*2.5*	*2.0*	*1.5*	*0.9*	*1.7*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.1	0.1	0.4	0.3	0.6	0.6	0.0	0.0
	Total	2.6	2.2	1.9	1.3	2.3	0.6	0.0	0.0
Alberta									
	Hydro								
	Wind								
	Solar								
	Biomass	0.0	0.0	0.0	0.0	0.0	-0.1	-0.8	-2.1
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*-0.1*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*-0.1*	*-0.8*	*-2.1*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	43.9	43.9	43.3	39.1	24.8	0.0	0.0	0.0
	Natural Gas	7.2	8.2	11.7	18.4	21.6	33.5	18.4	0.6
	No CCS	*7.2*	*8.2*	*11.7*	*18.4*	*21.6*	*33.5*	*18.1*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.3*	*0.6*
	Diesel / Fuel oil	1.1	0.9	1.3	0.7	5.1	3.0	0.4	0.0
	Total	52.3	53.0	56.3	58.3	51.5	36.4	18.1	-1.5
Saskatchewan									
	Hydro								
	Wind								
	Solar								
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.3
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*-0.1*	*-0.3*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	13.4	13.6	14.2	12.9	11.9	9.6	0.0	0.0
	Natural Gas	1.6	1.6	2.4	4.2	5.0	5.5	3.2	0.1
	No CCS	*1.6*	*1.6*	*2.4*	*4.2*	*5.0*	*5.5*	*3.2*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.1*	*0.1*
	Diesel / Fuel oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total	15.0	15.2	16.6	17.1	16.9	15.1	3.1	-0.2
Manitoba									
	Hydro								
	Wind								
	Solar								
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	1.0	0.6	0.1	0.1	0.0	0.0	0.0	0.0
	Natural Gas	0.0	0.0	0.0	0.0	0.9	0.6	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.9*	*0.6*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0
	Total	1.1	0.6	0.1	0.1	0.9	0.6	0.0	0.0

		GHG Emissions (Mt CO_2e)							
		2000	2005	2010	2015	2020	2025	2030	2035
Ontario									
	Hydro								
	Wind								
	Solar								
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	39.2	33.4	15.2	0.1	0.3	0.2	0.0	0.0
	Natural Gas	5.7	5.5	8.2	7.8	5.6	4.9	0.0	0.0
	No CCS	*5.7*	*5.5*	*8.2*	*7.8*	*5.6*	*4.9*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.4	0.7	0.3	0.1	0.2	0.5	0.0	0.0
	Total	45.4	39.7	23.7	8.1	6.1	5.5	0.0	0.0
Quebec									
	Hydro								
	Wind								
	Solar								
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0
	Natural Gas	0.1	0.2	0.2	0.1	1.4	1.0	0.0	0.0
	No CCS	*0.1*	*0.2*	*0.2*	*0.1*	*1.4*	*1.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.4	0.6	0.3	0.2	0.3	0.2	0.0	0.0
	Total	0.5	0.9	0.6	0.4	1.7	1.2	0.0	0.0
Atlantic									
	Hydro								
	Wind								
	Solar								
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	11.2	9.5	8.9	5.9	6.5	6.5	0.0	0.0
	Natural Gas	0.1	1.4	2.5	1.9	1.6	1.5	0.0	0.0
	No CCS	*0.1*	*1.4*	*2.5*	*1.9*	*1.6*	*1.5*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	8.0	11.9	4.5	5.0	4.0	4.0	0.0	0.0
	Total	19.3	22.8	15.9	12.8	12.1	12.0	0.0	0.0
Territories									
	Hydro								
	Wind								
	Solar								
	Biomass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	No CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Coal / Coal products	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Natural Gas	0.1	0.1	0.1	0.0	0.1	0.1	0.0	0.0
	No CCS	*0.1*	*0.1*	*0.1*	*0.0*	*0.1*	*0.1*	*0.0*	*0.0*
	CCS	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
	Diesel / Fuel oil	0.3	0.3	0.4	0.5	0.4	0.4	0.2	0.0
	Total	0.4	0.4	0.5	0.5	0.5	0.4	0.2	0.0