Net-Zero Pathways for Canada

Pillars of Decarbonization

Discussion Paper

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Executive summary

In mid-2022, Clean Prosperity initiated the Net-Zero Pathways for Canada research program with its modelling partner, Navius Research. This program explores different energy system pathways and the associated policies needed to achieve net zero in Canada, which we define as reducing greenhouse gas emissions to 50 megatonnes (Mt) per year by 2050.[1,2]

Our first report analyzed the impact of current federal climate policy on emissions reductions achieved by the 2050 time period. This analysis identified an anticipated emissions overshoot of +400 Mt/year by 2050 compared to our net-zero emissions goal, or what we term the "30-50 gap".[3]

This interim report presents the most recent learnings from the Net-Zero Pathways research program, and invites reactions and feedback. The report identifies common findings across five net-zero pathways that have been constrained to achieve our net-zero emissions target of 50 Mt/year by 2050. These pathways represent five different possible futures for Canada's energy systems, met by: (1) high electrification, (2) high electrification with high renewables, (3) fossil fuels with carbon capture and storage; (4) bioenergy; and (5) hydrogen.

In this report, we identify cross-cutting "pillars of decarbonization," which include potential opportunities that could help address the 30-50 gap. We also compare our model results with estimates of existing — as well as planned — capacity to help further inform the practical nature of this gap.

When we look across our pathway results for 2050, the following common elements emerge:

1. Increased electrification (up to 40% of final energy use) and electricity generation (43% to 74% increase relative to 2020), with significant contribution from solar and wind deployment.
Our results generally align with other net-zero studies and suggest a high degree of electrification occurs in the Buildings, Transportation, and Oil and Gas sectors.[4] This said, electricity in these sectors still makes up less than half of total energy consumption in 2050, even in pathways with a heavy electrification focus such as Electrification and High Renewables. The new solar and wind energy development in all pathways by 2050 (to constitute between 36% and 54% of total electricity generation) indicates that examination of land-use considerations, as well as energy storage and load management, will be critical. Due to the comparatively earlier technological and/or deployment stages of other options featuring in our results, the fully commercial status and cost decline of renewables suggests these are a particularly important and low-risk proposition to fully leverage.[5]

2. A major contribution from renewable natural gas (RNG) in the majority of our pathways (at 15%–26% of final energy use).
This model result is predicated on the successful domestic deployment of second-generation RNG technology, and also hinges on sizeable RNG import expectations being met.[6]

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RNG is particularly leveraged in our results (versus those of other studies) through the use of bioenergy with carbon capture and storage (BECCS). BECCS is applied to enable the scale of net-negative emissions needed to meet our aggressive net-zero target.[1] While these RNG estimates are substantial, the model identifies (1) RNG as a low cost option *vs.* other energy sources; and, (2) BECCS (as enabled through RNG) as a low cost option to reduce emissions remaining in the economy in 2050. We also note that prioritizing the optimal management of woody biomass residual feedstock (a major input for RNG production in the model) may become imperative in order to address the growing emissions impact of Canada's forest fires.[2]

3. A modest contribution from hydrogen (2%–5% of final energy use) as an energy carrier (i.e., fuel).[3]

Although hydrogen's contribution to final energy use is modest in all our pathways, which is a similar finding to other net-zero studies that explore its potential as an energy carrier, this contribution would still require significant infrastructure deployment.[4] This has important implications for costs and feasibility. We note that the atmospheric impacts of hydrogen leakage also need to be better understood.[5]

4. The presence of carbon capture, utilization and storage (CCUS) in all pathways, including in our High Renewables pathway.

Our model results largely explore Canada's onshore CO_2 storage potential, and range from the low end (the High Renewables pathway, at 89 Mt/year) to the high end (the Bioenergy pathway, at over 200 Mt/year), compared to other net-zero studies. The amount of abatement from CCUS is still notable in our High Renewables pathway, despite the near elimination of oil and gas production in this scenario (although at 108 Mt/year, total abatement from carbon capture and removal in this pathway is half to a quarter that of other pathways — see the table on the following slide). Model results also identify opportunities to deploy CCUS in specific provinces. In all cases, the scale of expansion projected far exceeds present-day availability of carbon capture technology and associated transport and storage infrastructure.

5. Significant expectations for carbon removal or net-negative emissions technology, such as direct air capture (DAC)[6] in pathways that do not leverage RNG (70–259 Mt/year), and for BECCS in pathways that do.[7]

Though the costs of DAC and BECCS are relatively high, the model employs these technologies in order to address emissions remaining in the economy in 2050. The nascent commercialization status of BECCS and early stage of DAC[8] suggests that significant technology readiness acceleration will need to occur to meet model expectations, particularly in scenarios that largely employ DAC to abate the high continued use of fossil fuels.[9] Also, the resource requirements of such technologies (e.g., energy draw, water use, feedstock availability), would benefit from further examination of the spatial and land-based considerations of high deployment scenarios.

Executive summary

At a glance: pillars of decarbonization

The following table displays high-level modelling results that cut across our five net-zero pathways, with highest values noted in yellow. These elements fall into three core "pillars" of decarbonization: **electrification with clean electricity generation**, **alternative fuels**, and **carbon capture and removal**. The elements indicate the main shifts in the energy economy that lead to net zero within our applied technological and cost parameters, and thus represent a set of theoretical options rather than specific strategies. Our results generally align with those in other net-zero reports that use similar models, though as noted leverage (1) the use of BECCS in RNG-heavy pathways to achieve our more aggressive net-zero targets (reflected in the amount of projected CCUS), and (2) DAC for other pathways. These findings illustrate the scale of efforts required to achieve net zero on multiple fronts. Moreover, the results have interdependencies that require them to be developed concurrently in order to achieve optimal net-zero outcomes. For example, deploying DAC without also building up renewable generation capacity would be sub-optimal, given DAC's high energy demands.

Maximum values

Pillar	Element of interest	NET-ZERO PATHWAYS				
		Electrification	Fossil with CCUS	High Renewables	Bioenergy	Hydrogen
Electrification with clean electricity generation	**Electricity generation** in 2050 compared to 2020	74% increase	43% increase	60% increase	50% increase	45% increase
	Energy consumed as electricity in 2050[1] (% of total energy use across the economy)	38%	28%	40%	29%	30%
Alternative Fuels	**RNG consumption** in 2050 (% of total energy use across the economy)[2]	15%	0%	26%	24%	22%
	H_2 consumption in 2050 (fuel; % of total energy use across the economy)[3]	3%	2%	3%	3%	5%
Carbon capture and removal	**CCUS** in 2050 (CO_2 captured)	130 Mt	160 Mt	89 Mt	206 Mt	203 Mt
	DAC in 2050 (Liquid-DAC)	70 Mt	259 Mt	19 Mt	13 Mt	34 Mt
	Total abatement (CCUS + DAC)	200 Mt	419 Mt	108 Mt	219 Mt	237 Mt

Executive summary

Our secondary research into the present status of electrification expansion, RNG, hydrogen, and carbon capture and removal technologies in Canada shows that a **significant delta exists** between current-day projects/resources versus our pathway results for 2050. These findings are detailed in the table on the following slide (**columns A and B**), and clearly illustrate the magnitude of effort needed to reach the modelled outcomes.

We also find that the availability of comprehensive plans[1] to make progress tin these areas across Canada is limited (**column C**),[2] which means there is a gap between what is required to achieve net zero, and what key players in the energy system are currently projecting and planning for (e.g., **columns A + C do not equal column B**). This is a critical alignment gap which will require much more coordination within and across regions and governments to address. Initial research has also identified additional implementation challenges (**column D**) that pose barriers to deployment.

Given these initial observations, the planning horizon required for realizing large-scale infrastructure change,[3] and the depth of systemic change needed,[4] we argue that this net-zero "alignment and deployment gap" is critical to address and needs to feature much more prominently in Canada's net-zero efforts.

In our view, Canadian net-zero research should more closely examine the practical feasibility of proposed net-zero technologies and approaches — and in particular, their realistic potential for development and deployment in various sectors and provinces.

Our next research phase will therefore examine how our pillar results can apply to high-emissions sectors, as well as evaluate the provincial backdrops for operationalizing net-zero opportunities, which includes the changing role of fossil fuels in the economy. Our supporting work will explore the spatial and land-use considerations associated with deployment of various net-zero projections through a series of research briefs. Our final report will include a suite of "30-50" policy recommendations to help close the gap between the projected outcomes of current policy, and Canada's goal of achieving net-zero by 2050.

Note: As with all modelling efforts, the quantitative results in this report are the outcome of numerous assumptions (such as set input parameters and costs, projected technology adoption, and many other factors). All results should be considered directional, and are shared in the spirit of contributing to an open discussion of our net-zero pathway directions and priorities.

We welcome your feedback and invite engagement on this effort at research@cleanprosperity.ca

Comparing our current context to modelled net-zero outcomes

Element of interest	Current status (A)	Modelled requirement range for net zero in 2050 (B)	Development/planning underway (C)	Select implementation challenges identified (D)
Electrification	**17%** of energy is consumed as electricity across the economy.	**28%–40%** of energy is consumed as electricity across economy.	Policy incentives and targets to electrify transportation and other sectors underway in some provinces (QC, BC).[1]	• Access to reliable electricity at scale (primarily for industrial applications) • Sector feasibility and cost barriers for changing technologies (e.g., full fleet turnover) • Substantial new distribution infrastructure buildout for some sectors
Electricity generation	**636 TWh** generated in Canada in 2020.[2]	**917–1116 TWh in 2050**. Of this, **36%–54%** is met by new renewables (solar/wind).	Many provincial electricity authorities/regulators are not forecasting or planning for collective net-zero objectives (for electrification, renewables generation, and to consider other emerging demands for electricity, such as DAC).	• Generation capacity buildout • Transmission and distribution infrastructure upgrading and buildout; land use consultation and engagement • Accommodating and expanding storage • Coordinated electricity planning and net-zero alignment between provinces and federal level
Renewable natural gas	39 projects producing **18 PJ/year** of RNG.	Up to **~1000 PJ/year** of RNG production, combined with up to **1700 PJ/year** in RNG imports. Significant leveraging of **BECCS** for net-negative emissions/geological storage (select provinces).	Limited and varied provincial plans to expand RNG production (despite some blending targets); wide range of estimates on feedstock potential. No province has examined BECCS deployment in depth.	• Secure feedstock availability and limitations on use • Infrastructure buildout to harness first-generation RNG and BECCS opportunity • Technological readiness acceleration of second-generation RNG and BECCS • Secure access to imported RNG from the U.S. (per modelled results)
Hydrogen	**Technological development** of hydrogen for energy carrier applications.[3] **360 PJ** of grey hydrogen currently produced as feedstock for industrial processes.	From **180 to up to 500 PJ** of hydrogen produced as a fuel (3%–5% of energy use), primarily for blending with natural gas and transportation by 2050. Hydrogen produced for industrial processes is assumed to be green/blue hydrogen.	Federal strategy anticipates from **480–2400 PJ** of hydrogen demand by 2050, including for energy carrier uses (30%). **75–190 Mt** of CO_2 abatement is anticipated in provincial and federal plans by 2050, from converting grey to green/blue hydrogen, and expanding hydrogen use to transportation and natural gas services.	• Mismatch between net-zero projections vs. federal vs. provincial planning estimates for hydrogen • Limited role for hydrogen as a fuel in modelled energy economy; however substantive new infrastructure buildout still required for use beyond industrial feedstock (e.g., to Transportation sector) • Questions around the atmospheric impact of hydrogen leakage remain to be addressed
Carbon capture and storage (CCUS)	**4 Mt CO_2/year** currently captured.	From **90 Mt up to 200 Mt CO_2/year** captured and stored in 2050, primarily in Alberta.	**16 Mt** planned by 2030 under the federal Carbon Management Strategy.[4] Some CO_2 transport and storage infrastructure available in Alberta, supportive regulatory environment. Limited capture infrastructure in Saskatchewan to date.	• Regulatory and permitting challenges • Broad mechanisms to incentivize and prioritize permanent storage (or for other permanent uses) • Lack of existing infrastructure for geological carbon storage outside of Alberta and Saskatchewan (limited)
Direct air capture (DAC)	Largely in **pre-commercial or early pilot** stage (including liquid DAC, the main technology modelled). DAC is a carbon dioxide removal (CDR) technology.	Nearly **260 Mt CO_2/year** in the Fossil with CCUS pathway; **13–70 Mt CO_2/year** in other pathways by 2050. Significant additional carbon dioxide removal will be needed to remain below 1.5C of long-term warming (a much more ambitious goal than net-zero).	In continued research and development phases.	• L-DAC implies significant use of energy (electricity and heat) • Technological readiness, large-scale feasibility and scale-up potential of L-DAC (and other CDR) as yet unknown • Expanded regulatory support needed to enable storage of captured carbon (or for other permanent uses) • Lack of natural and manmade infrastructure outside of Alberta and Saskatchewan for storage of removed carbon

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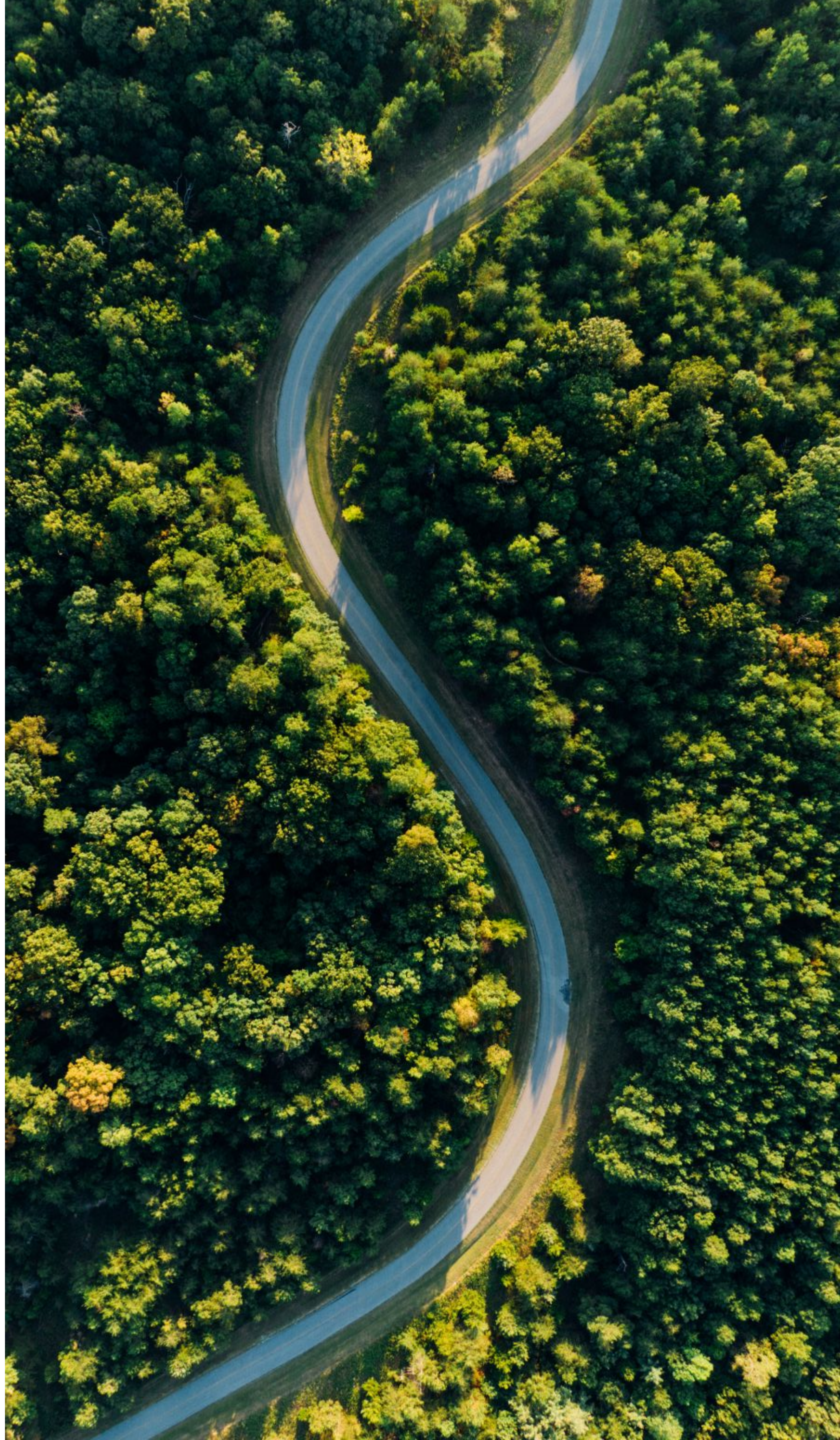


Introduction

Section 1

Introduction

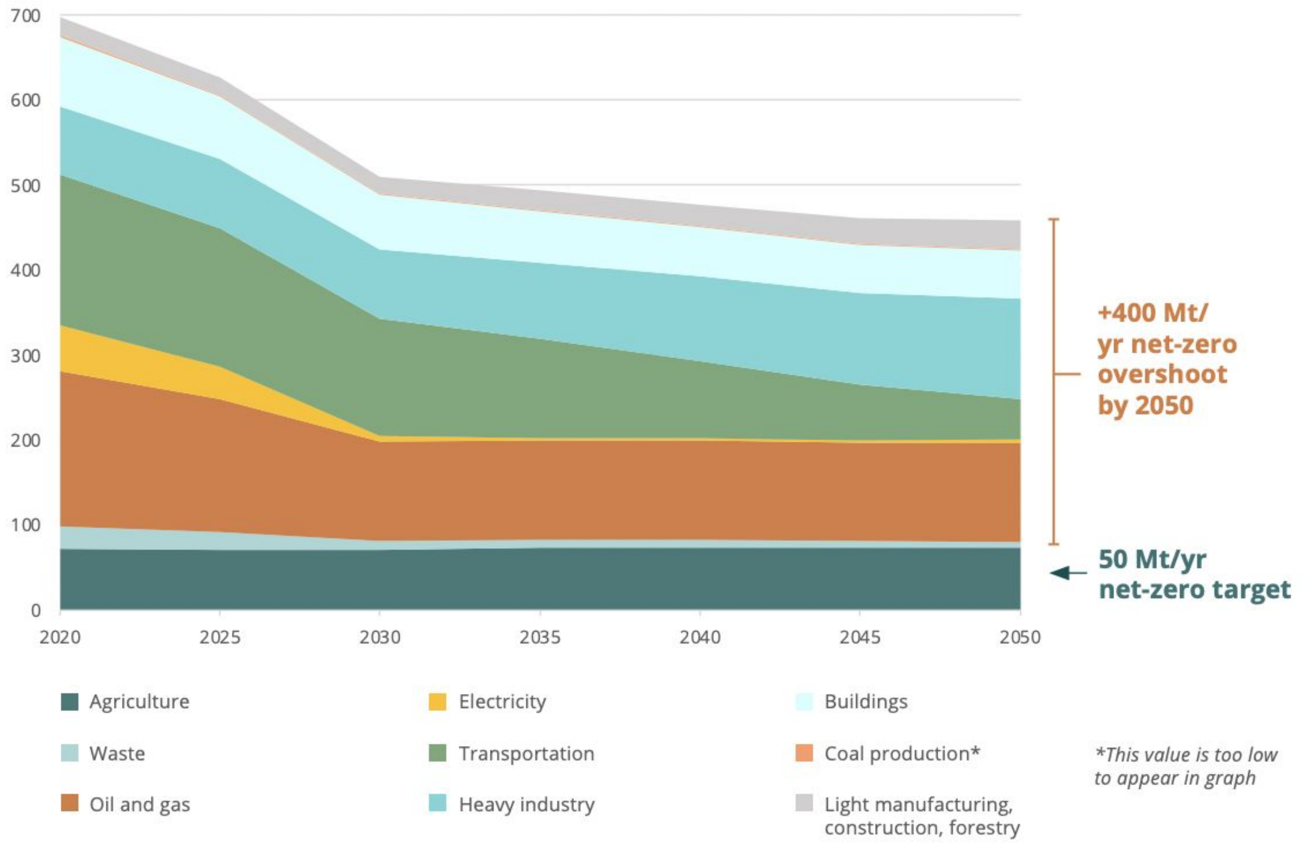
Meeting the 30-50 gap

In spring 2022 we launched our Net-Zero Pathways for Canada research program to explore different energy system pathways and policies for Canada to achieve net zero, which we define as reducing emissions to 50 megatonnes (Mt) a year by 2050.[1]

Although our modelling of current federal policy projects good progress against near-term 2030 targets (see the figure at right), by 2050 we anticipate a significant emissions overshoot of 400 Mt/year as documented in our 2023 paper.[2] We call this the **30-50 gap.**

Our results suggest that further action to consider and narrow the 30-50 gap is imperative to realize net zero. This report identifies elements that are common across our net-zero pathways by 2050, which we present in order to identify opportunities that can help achieve our 2050 ambitions.

Illustrating the 30-50 gap



Methodology

Model description and analytical approach

This work was conducted using the **Navius Research gTech** energy economy model, in combination with Navius' supporting **Integrated Electricity Supply and Demand (IESD) model**.

- **gTech** is a technologically-detailed, general equilibrium model that simulates a wide range of features of the energy economy, such as energy supply markets, fuel production, consumer preferences, sector-specific energy use, economic growth, greenhouse gas emissions, and more.[1]
- **IESD** is a capacity addition and electricity dispatch model that simulates how the Canadian electricity system changes under different policy and economic conditions.

The gTech model incorporates over 300 technologies with more than 80 end-uses. Among them are a range of abatement technologies for carbon capture, utilization and storage (CCUS) and direct air capture (DAC); first- and second-generation biofuels; several methods of hydrogen production; and energy storage technologies.

For this project, Navius designed a customized version of gTech. Key inputs for the customized model were developed by Navius and Clean Prosperity. These include technology availability, costs, and policy assumptions.[2,3]

We defined **five net-zero pathways** to simulate different energy systems Canada could use to achieve net-zero emissions by 2050 (detailed in the next slide). In our analysis of the pathway results, we have identified the **key pillars that are necessary to reaching net-zero**, irrespective of the exact technological approach Canada takes to decarbonize its economy.
In addition to modelling, we have conducted a **literature review** to compare our results with those from other Canadian net-zero studies, and researched how results measure up against available estimates of present-day and future potential. We have also employed map-based datasets to understand how model outcomes play out against Canada's current resources and infrastructure, which is part of our pending **downscaling work**.[4]

Net-zero pathways

Our pathways model Canada's future net-zero energy economy using parameters designed to favour five different technology areas, specifically: (1) high electrification,[1] (2) high electrification that is largely met with renewables,[2] (3) bioenergy,[3] (4) hydrogen,[4] and (5) fossil fuels combined with carbon capture, utilization and storage (CCUS).[5]

These pathways largely vary by the cost of various technologies and their availability, as shown in the table below. As noted, all pathways are set to achieve net-zero emissions in 2050 (50 Mt/year).[6,7] The high renewables pathway also models an oil and gas production wind down by 2050 to evaluate the possible implications of such a constraint.[8]

Parameters set for net-zero pathways[9]

Pathway	DAC cost	New nuclear available	SMnRs available	Battery cost	EV cost	Heat pump cost	CCUS cost	Hydrogen cost	FCEV cost	Solar and wind cost	Biofuels cost
1. Electrification	high	yes	yes	low	low	low	REF	REF	REF	low	high
2. Renewables	high	no	no	low	low	low	REF	REF	REF	low	high
3. Bioenergy	high	no	no	high	REF	high	low	REF	REF	high	low
4. Hydrogen	high	no	no	high	REF	high	low	low	low	high	REF
5. Fossil fuels with CCUS	REF	yes	yes	high	REF	high	low	REF	REF	high	REF

Top-line results

Section 2

The pillar framework

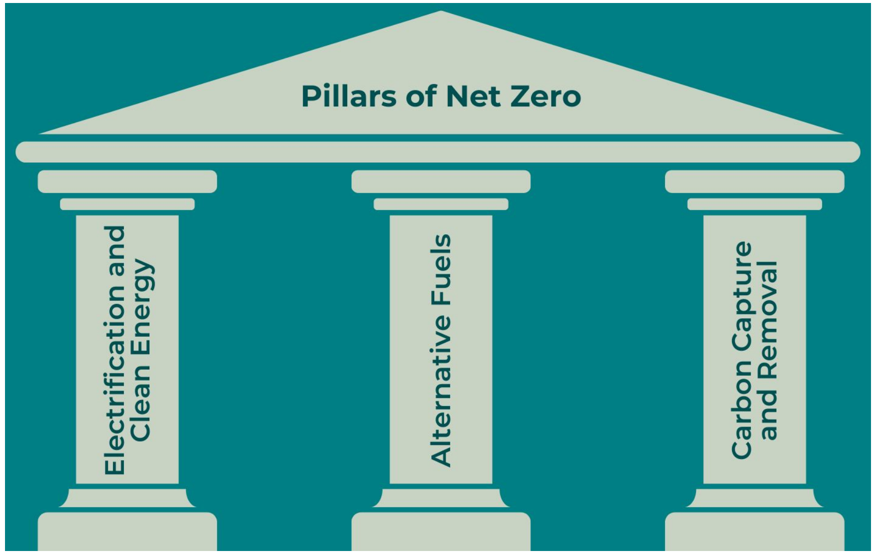
The analysis of our net-zero pathways centres upon three principal categories, or "pillars", that enable achieving net-zero emissions across the economy: **(1) electrification and clean electricity, (2) alternative fuels, and (3) carbon capture and removal.** These pillars consistently appear across the net-zero pathways.[1]

1. The electrification and clean electricity pillar shifts away from fossil-powered technologies and towards electric-powered technologies (where such a move results in reduced emissions), in tandem with growth in clean electricity generation.

2. The alternative fuels pillar includes a variety of low- or zero- carbon fuels such as renewable natural gas (RNG), hydrogen, liquid biofuels (e.g., biodiesel), and solid biomass. These fuels can replace fossil fuels as an energy source in many sectors (including electricity generation), with varying degrees of technological modification, and with new or modified infrastructure development.

3. The carbon capture and removal pillar comprises technologies that capture or remove carbon emissions for storage or subsequent use. These fall into two principal categories: carbon capture, utilization and storage (CCUS), whereby emissions are captured at the point source; and carbon dioxide removal (CDR), whereby carbon is removed from the atmosphere.

CDR can theoretically be deployed to offset ongoing emissions in harder to abate sectors, as well as to draw down accumulated historical emissions. In our modelling, CDR includes direct air capture (DAC) and bioenergy with carbon capture and storage (BECCS), although there are a range of other removal technologies that are also in early development.



The pillar framework

The three pillars should be understood as **dynamic and interconnected**, which implies that:

1. Elements in each pillar (as described in this work) **are not exhaustive and can change over time**, especially as other options become possible and/or more advantageous in the future.[1] Deployment is also influenced by additional factors, such as the efficiency of energy production and end-use, permitting and land-use considerations, factors that can affect resource availability (e.g., climate change, which can alter wind, water, and solar resources as well as biofuel feedstocks), and myriad other aspects.

2. Varying deployment within one pillar can have **knock-on effects** on the others. For example, reducing the deployment of alternative fuels may necessitate more carbon capture or increased electrification in order to achieve net zero. As another example, increased reliance on carbon capture and removal implies increased demand for electricity and fuel in order to operate such facilities.

3. Furthermore, some forms of emissions reduction **do not fit neatly** into a single pillar. A notable example is BECCS, where biofuel consumption is paired with CCUS to yield net-negative emissions. In this sense, the function of BECCS with respect to emissions is similar to that of DAC, yet BECCS could also be considered as part of clean electricity and/or alternative fuel deployment in other sectors.

In the absence of being able to accurately predict what will actually transpire in the future, it will be important to **move forward all three net-zero pillars simultaneously,** regardless of the exact supporting technology combination the model currently projects.

With this context in mind, in the remainder of this document we present our modelling results and pay specific attention to five elements that fall into the three-pillar framework, namely: **electrification with clean electricity generation**; **renewable natural gas**; **hydrogen**; **carbon capture, utilization and storage**; and **direct air capture.** While other elements, such as solid or liquid biofuels, can also play an important role in emissions reduction, we do not examine them extensively due to their limited role in our model results (e.g., liquid biofuel use is largely limited to the Transportation sector).[2]

The pillar framework

When we examine our results in 2050 (overleaf), the following five elements emerge:

1. **Increased electrification and electricity generation,** with a significant contribution from new solar and wind across all pathways (36%–54% of total generation).

2. The presence of bioenergy, and especially **renewable natural gas** in the majority of our pathways. RNG-heavy pathways (High Renewables, Bioenergy and Hydrogen) in particular leverage the application of BECCS to generate the net-negative emissions needed to meet our ambitious net-zero target.

3. A modest contribution of **hydrogen as an energy carrier** to final energy use (at 2%–5%), largely as a result of hydrogen being outcompeted by other fuels.[1]

4. Significant deployment of **carbon capture, utilization and storage**[2] in all pathways, including in our High Renewables pathway. For High Renewables, total abatement (CCUS + DAC) is half to a quarter that of other pathways, largely due to the oil and gas production phaseout applied in this scenario.

5. Significant **direct air capture** in pathways that do not leverage RNG/BECCS, particularly in our Fossil with CCUS pathway, and Electrification to a lesser extent.

Maximum values

Pillar	Element of interest	NET-ZERO PATHWAYS				
		Electrification	Fossil with CCUS	High Renewables	Bioenergy	Hydrogen
Electrification with clean electricity generation	**Electricity generation** in 2050 compared to 2020	74% increase	43% increase	60% increase	50% increase	45% increase
	Energy consumed as electricity in 2050[3] (% of total energy use across the economy)	38%	28%	40%	29%	30%
Alternative Fuels	**RNG consumption** in 2050 (% of total energy use across the economy)[4]	15%	0%	26%	24%	22%
	H_2 consumption in 2050 (fuel; % of total energy use across the economy)	3%	2%	3%	3%	5%
Carbon capture and removal	**CCUS** in 2050 (CO_2 captured)	130 Mt	160 Mt	89 Mt	206 Mt	203 Mt
	DAC in 2050 (Liquid-DAC)	70 Mt	259 Mt	19 Mt	13 Mt	34 Mt
	Total abatement (CCUS + DAC)	200 Mt	419 Mt	108 Mt	219 Mt	237 Mt

Net-Zero pathways results

Common findings across pathways in 2050

Electricity consumption *(yellow)* is similar across pathways — making up from 28%–40% of total final fuel composition. A large portion of the electricity generated is renewable-based (36%–62%). Notably, total energy consumption in the High Renewables pathway is much lower than in every other pathway. This is attributable to the decline in the use of fossil fuels as a result of the oil and gas production phaseout constraint applied,[1] combined with greater energy efficiency due to electrification.

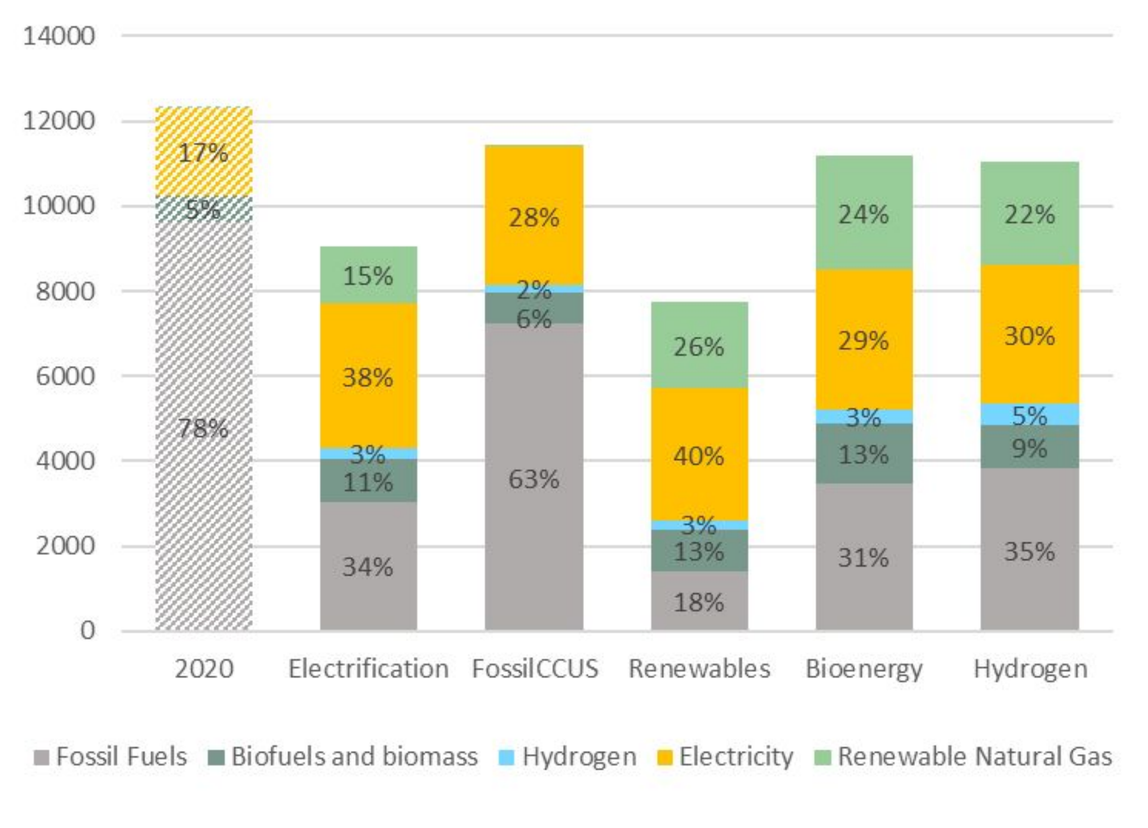
RNG consumption *(light green)* makes up from 15%–26% of total energy use in our net-zero pathways (except the Fossil with CCUS pathway, and the Electrification pathway to a lesser extent).

Hydrogen fuel *(blue)* makes up 2%–5% of energy use in the pathways, and is highest for the Hydrogen pathway (5%).

Liquid biofuels and solid biomass *(dark green)* make up 6%–13% of energy use in all net-zero pathways.

Continued fossil fuel use *(grey)* necessitates the use of CCUS for all pathways, as well as DAC for select pathways (Fossil with CCUS, Electrification). BECCS is also leveraged in combination with RNG to offset this use in select pathways (High Renewables, Bioenergy, Hydrogen).

Share of total energy consumption by source in 2050, Canada (PJ)[2]



Defining pillars and their comprising elements

Pillar	Pillar elements/areas of interest	Description	Role in reducing emissions
Electrification and clean electricity	**Electrification**	Shifting away from technologies that use unabated fossil fuels to technologies that are powered by cleaner electricity.	Electrically-powered technologies are typically **more efficient**, which reduces total energy demand.[1] Electricity is a cleaner form of energy provided that it is **produced using low-emission or emission-free sources.**
Alternative fuels	**Renewable natural gas**	Using renewable natural gas in the place of fossil natural gas or other fossil fuels. Renewable natural gas, or biomethane, is a gaseous biofuel that can be produced from various biomass sources through processes such as anaerobic digestion, and second-generation processes such as gasification and methanation.	RNG is considered to be carbon neutral.[2] Therefore, when used instead of fossil natural gas, it **displaces emissions that would have been emitted via natural gas combustion**. When paired with CCUS, replacement of fossil fuels with RNG would yield **net-negative emissions (BECCS).** This latter aspect is a particularly critical lever for select pathways to reach net zero.[3]
	Hydrogen	Using hydrogen as an energy carrier, typically in place of fossil fuels.[4]	Hydrogen is a **carbon-neutral energy carrier**. When used in place of fossil fuels, it displaces the emissions that would have been emitted via fossil fuel combustion. Hydrogen production can have an emissions impact depending on its production pathway.
	Other: solid and liquid biofuels, etc.	Solid and liquid biofuels are not examined in detail in this document as they do not appear extensively (across the economy) in our results.[5]	
Carbon capture and removal	**Carbon capture, utilization and storage**	Capturing carbon dioxide from large point sources and transporting it for use (e.g., in industrial processes, enhanced oil recovery), or long-term storage.	CCUS technology traps carbon dioxide at the point source, thereby reducing source emissions by up to 90% or more.[7] CCUS is typically deployed by large emitters in heavy industry, oil and gas operations, and fossil-fuel-based power plants.[6] Geologic storage can be employed to **permanently sequester carbon dioxide.**
	Direct air capture	A carbon dioxide removal technology that removes carbon dioxide directly from the air, for use or for long-term storage.	DAC **takes up carbon dioxide directly from the air**. Theoretically, as DAC does not need to be placed at a specific point source,[8] it can be used to reduce total emissions across the economy by removing carbon dioxide from the atmosphere and sequestering it into long term storage (net-negative emissions).

Electrification and clean electricity

Section 3

+ Overview
+ Pathway results for 2050
+ Comparison to other studies
+ Current state of play
+ Deployment gap considerations

Main points

Role of electrification and clean electricity as a pillar of decarbonization

Electrification is central to the decarbonization of nearly all sectors in our net-zero pathway results. Significant shifts are observed in the Transportation, Buildings, and Oil and Gas sectors (among others). However, in all sectors except Buildings, the portion of energy consumed as electricity remains well below 50% by 2050, with the cross-economy total ranging between 28% and 40% of energy consumed as electricity. We posit that **more electrification is possible** than shown in our results, especially if given added policy support to lower costs and overcome implementation barriers.[1]

Combined with other drivers of demand, the degree of electrification achieved in our net-zero results translates to about **40% to 50% in electricity demand growth by 2050**,[2] which is lower than estimates in some other Canadian studies. It is important to note that the model employed does not account for all emerging technologies, such as quantum computing and artificial intelligence, which will likely further increase electricity demand.[3]

Our results show that growth in electricity demand is met by **significant added renewable generation capacity from solar and wind,** with some growth in natural gas-based generation coupled with carbon capture and storage (CCUS) abatement. Other options for electricity generation, including hydro, new nuclear (e.g., small modular reactors), and geothermal, have not been fully explored in our analysis. Our upcoming work aims to consider options to advance electrification in particular subsectors (e.g., industrial operators).[4]

When we compare Canada's current electricity generation to net-zero generation projections, it is clear that **significant expansion is needed in all provinces**. Most of the provincial projections that we reviewed do not project this level of demand growth, and further, few utilities consider collective net zero goals as part of their planning processes to date.

Increased electrification combined with expanded low-carbon generation is generally considered to be an essential part in achieving net zero for Canada. While the model findings support this direction, a number of questions arise on how we can advance electrification, and in particular how we can **better align net-zero opportunities** with the actual planning that is underway on the ground. This is a major area of consideration given the need for expanded clean electricity generation across the board, as well as the impacts associated with deploying particular net-zero technologies at the scale and impact projected by the results.

We conclude that more research is needed to **identify additional opportunities and required support for electrification**, especially given Canada's low-carbon electricity grid and high potential for additional renewable and low-carbon generation capacity to help achieve net zero.

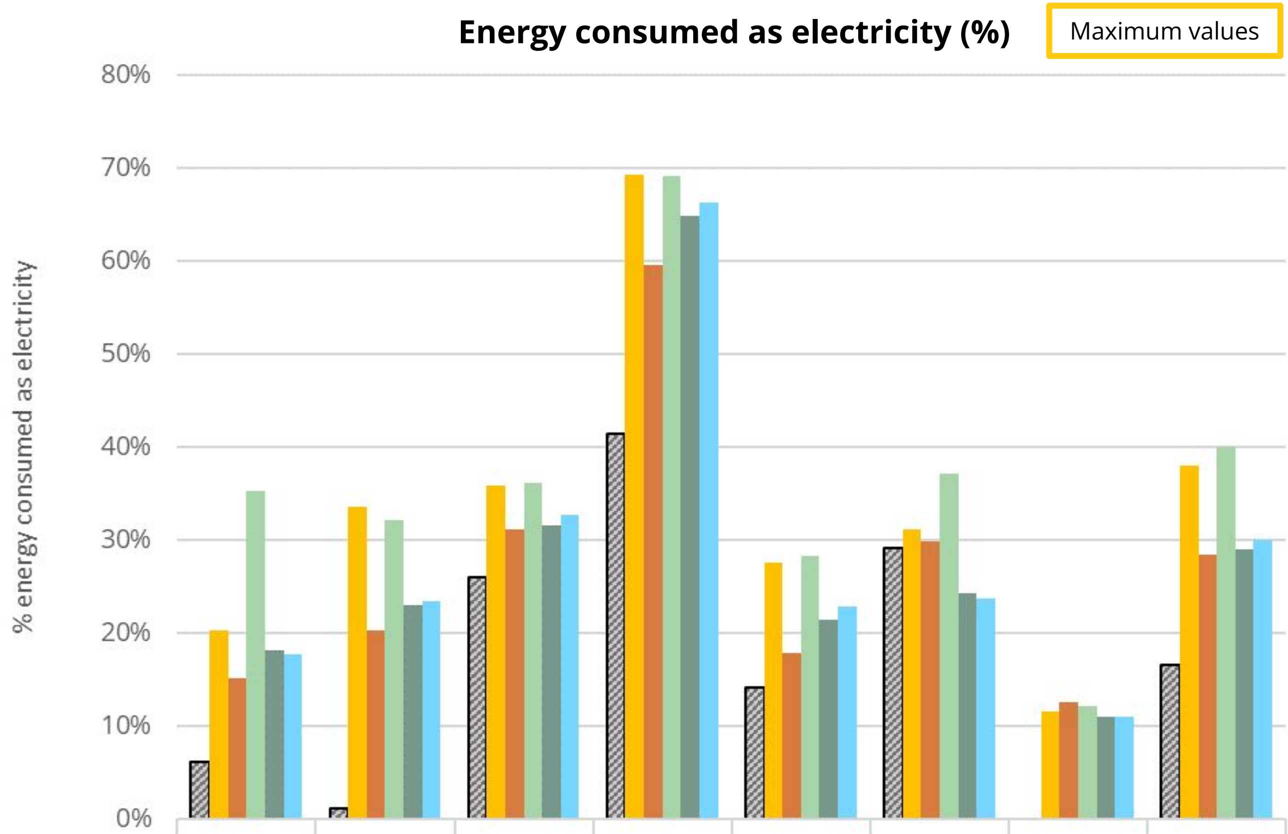
Pathway results for 2050

Electricity consumption across sectors

Our results show **electrification taking place in all pathways and nearly all sectors**. Irrespective of these gains, electricity still makes up less than half of total energy consumption in 2050, even in pathways with a heavy electrification focus such as High Renewables (40%) and Electrification (38%).

Sectors making significant shifts over time include **Transportation**, **Buildings** and **Oil and Gas**. The **Buildings** sector stands out as the largest consumer of electricity in 2050, making up over 40% of electricity use in all pathways (see next slide). Electricity consumption in this sector climbs from 288 terawatt hour (TWh) in 2020 to 373–401 TWh in 2050, primarily as a result of a move from natural gas powered heating to electric heat pumps and water heaters.[1]

In **Transportation,** electricity use climbs to 118–164 TWh (20%–34% of total energy consumed) in 2050 from a modest 9 TWh in 2020.[2] This low starting point implies a large buildout of new supporting infrastructure, compared to sectors with already high electricity use.



	Oil and Gas	Transportation	Heavy Industry	Buildings	Agriculture	Light Manufacturing, Construction, Forestry	DAC	Total
2020 Baseline (Electrification)	6%	1%	26%	41%	14%	29%	0%	17%
Electrification 2050	20%	34%	36%	69%	28%	31%	12%	38%
Fossil CCUS 2050	15%	20%	31%	60%	18%	30%	13%	28%
Renewables 2050	35%	32%	36%	69%	28%	37%	12%	40%
Bioenergy 2050	18%	23%	32%	65%	21%	24%	11%	29%
Hydrogen 2050	18%	23%	33%	66%	23%	24%	11%	30%

Pathway results for 2050

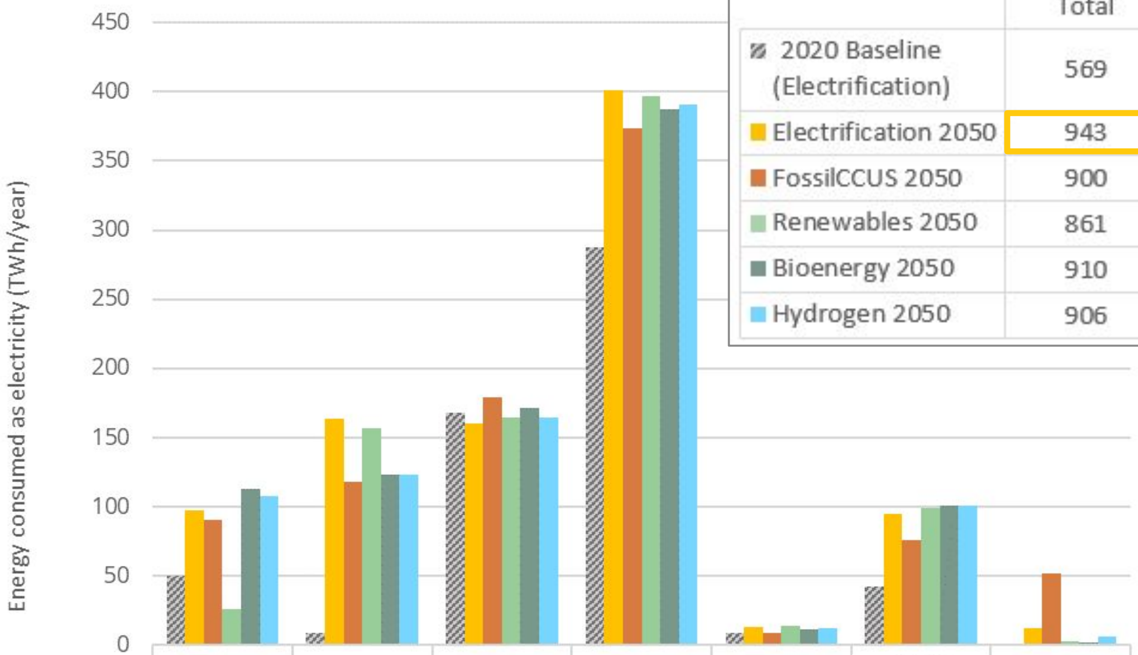
Electricity consumption across sectors

Electrification in the **Oil and Gas** sector is anticipated only in certain subsectors, mainly in natural gas production and processing; oil, gas, and CO_2 transmission; and for liquified natural gas production. Electricity makes up 15%–35% of energy consumed in 2050 (equivalent to 26–113 TWh), with the remainder of energy consumption being fossil natural gas with CCUS.[1]

The **Heavy Industry** sector sees relatively little change in electricity use, both in terms of proportion and absolute consumption. Electricity use in **Light Manufacturing** approximately doubles in most pathways between 2020 and 2050 (from 42 TWh to 76–101 TWh). However, this absolute increase is reflective of overall growth of the sector rather than significant electrification.[2] A central issue is that these sectors use high-temperature heat for many processes which is more challenging to electrify.[3] As a last observation, **significant direct air capture (DAC)** build-out has implications for electricity use. For the Fossil with CCUS pathway, which uses DAC as a major abatement measure, this results in an additional ~50 TWh of consumption in 2050 (5% of total electricity consumption for this pathway).

Overall, our results suggest that while there is significant opportunity for cost-effective electrification, further research is needed to understand where and **how sectoral barriers could be overcome** to increase the share of electricity in total energy consumption, as well as to accelerate **opportunities in high-potential areas** like Transportation and Buildings.[4]

Energy consumed as electricity (TWh)



Total electricity consumption (TWh)

	Total
2020 Baseline (Electrification)	569
Electrification 2050	943
FossilCCUS 2050	900
Renewables 2050	861
Bioenergy 2050	910
Hydrogen 2050	906

	Oil and Gas	Transportation	Heavy Industry	Buildings	Agriculture	Light Manufacturing, Construction, Forestry	DAC
2020 Baseline (Electrification)	50	9	168	288	9	42	0
Electrification 2050	98	164	160	401	13	95	12
FossilCCUS 2050	91	118	179	373	9	76	52
Renewables 2050	26	157	164	397	15	99	3
Bioenergy 2050	113	123	172	388	12	101	2
Hydrogen 2050	108	123	165	391	12	101	6

Maximum values

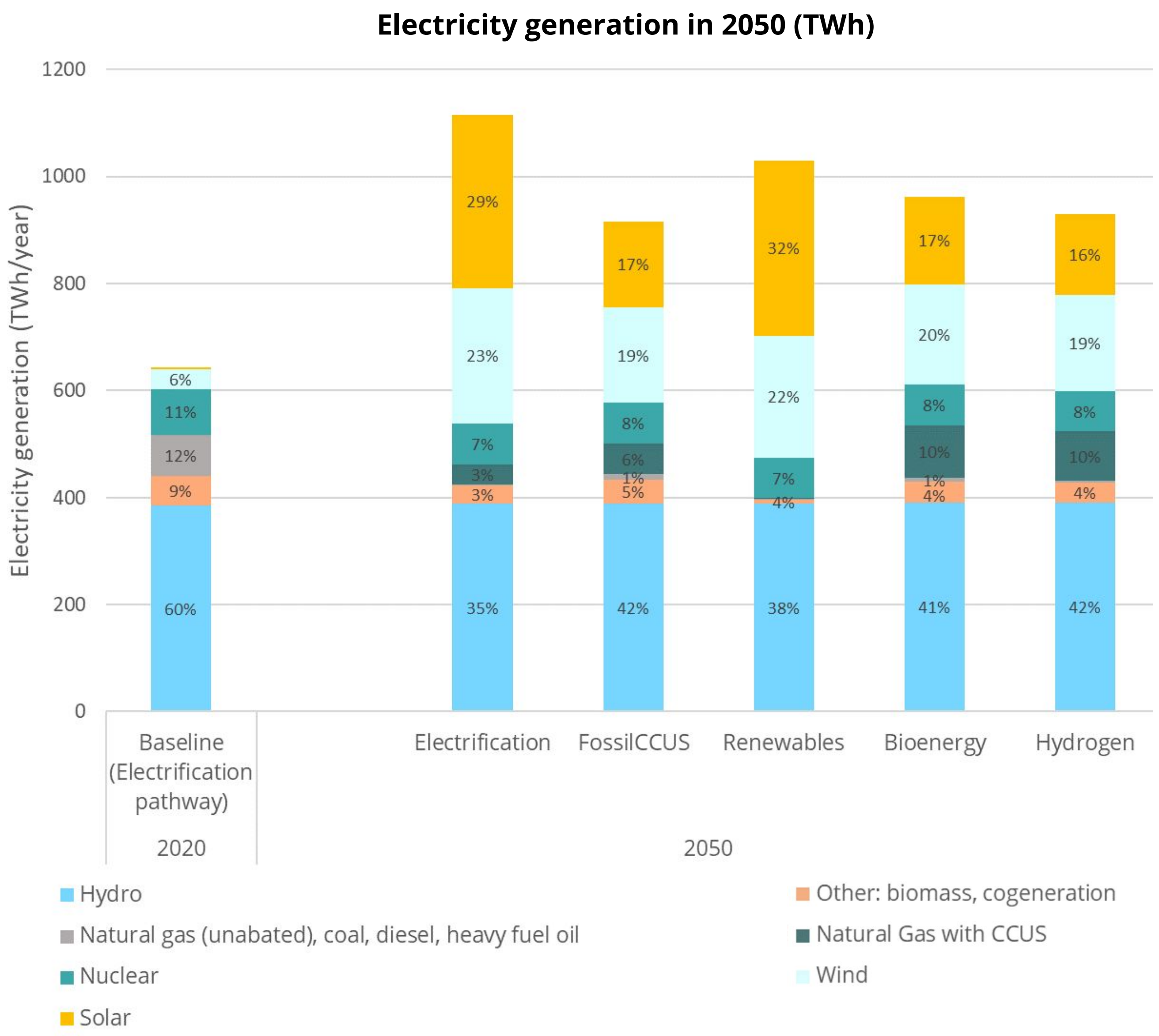
Pathway results for 2050

Electricity generation mix

Our results show that growth in electricity consumption is supported by growth in generation, primarily from the expansion of renewable sources including **solar and wind**, as well as some **natural gas with CCUS.**[1] In all pathways except for Fossil with CCUS, the natural gas used for power generation in the net-zero pathways is renewable natural gas (RNG) (94% to 99%).[2]

The pathways with a focus on electrification (**Electrification** and **High Renewables**) see the highest increase in total generation, with solar and wind comprising more than half of generation in 2050. Even in the high-fossil pathway (Fossil with CCUS), growth in electricity generation is made up primarily by solar and wind.

Our results emphasize the **opportunity for renewables across all pathways in the Canadian electricity mix**, which is already high in hydropower, and the potential for additional abatement with CCUS. Given the high penetration of intermittent renewables, **energy storage and load management** are important to incorporate into grid design to ensure system reliability.[3]



Electricity demand and generation in other studies

Comparing electricity generation and consumption research

Most Canadian net-zero studies project that **electricity generation will grow 1.5x to 2x** across Canada between 2020 and 2050. This generally translates to even **higher growth in generation capacity** (on the order of 3x). Growth tends to be higher in net-zero scenarios compared to other policy scenarios.

In comparison with other Canadian net-zero studies, our projections for electricity consumption and generation fall roughly in the middle of the pack (see Slide 25). Our results suggest an **increase in electricity consumption of 40%–50% compared to 2020**, which is not as high as some estimates. However, we expect growth in generation of between 43% and 74%, which is on par with other studies (though we note the model does not yet account for increased demand from emerging future uses, such as AI).

In most sources, generation growth is primarily from added **wind and solar**, even in non-net-zero or fossil-based scenarios (see Slide 26). This latter observation is noteworthy as it reflects the present and anticipated cost declines of solar and wind generation, which result in these technologies increasingly proliferating in the energy system.

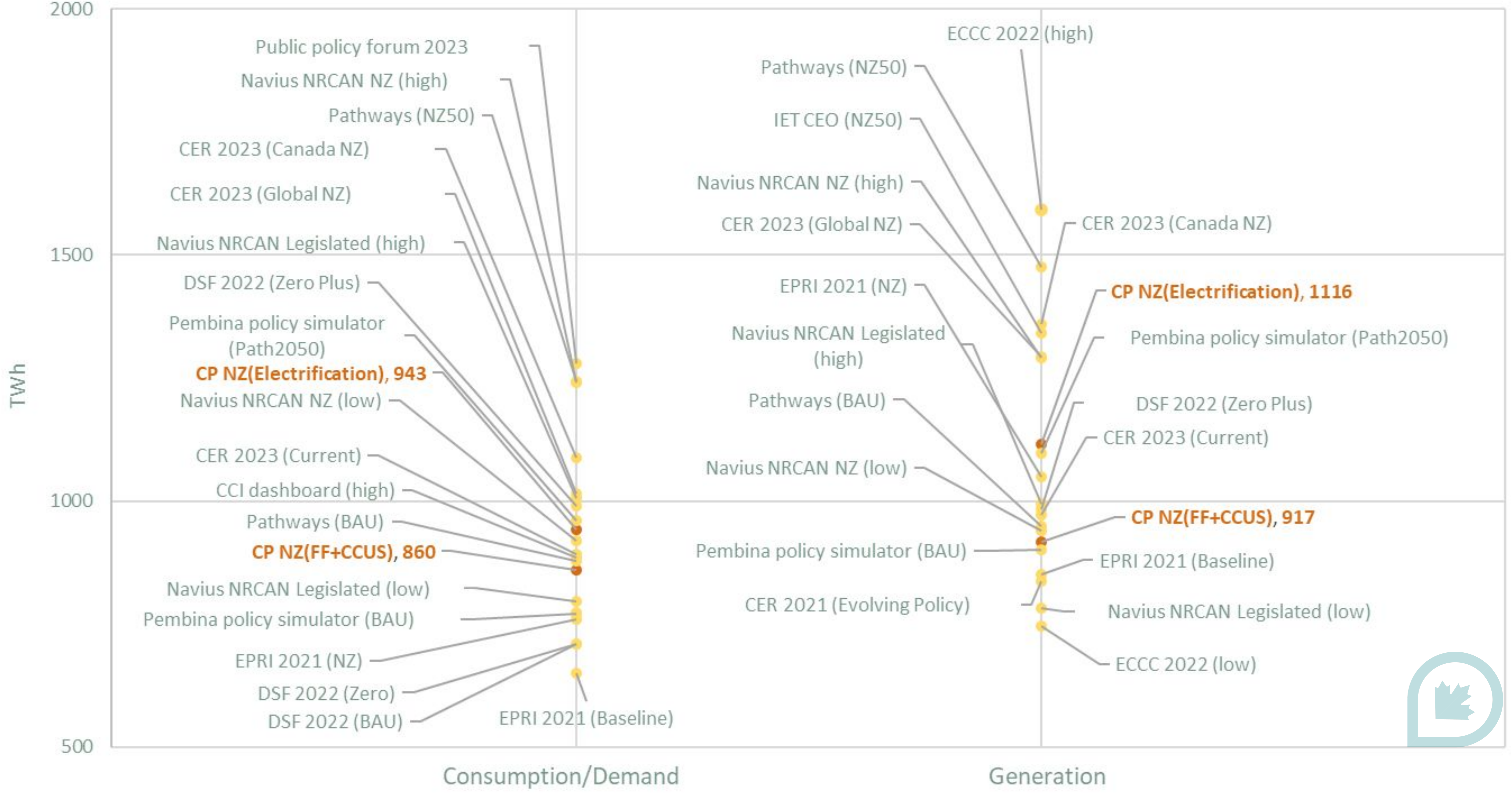
Some studies indicate growth in natural gas with CCUS, small modular nuclear (e.g., CER 2023 and EPRI 2021), and/or added large hydro (e.g., CER 2023).[1,2]

In our net-zero pathways **growth in generation comes primarily from solar and wind**. Our results are generally more optimistic on solar (top-range) and less optimistic on wind (mid-range), which reflects our solar/wind cost parameters.[3]

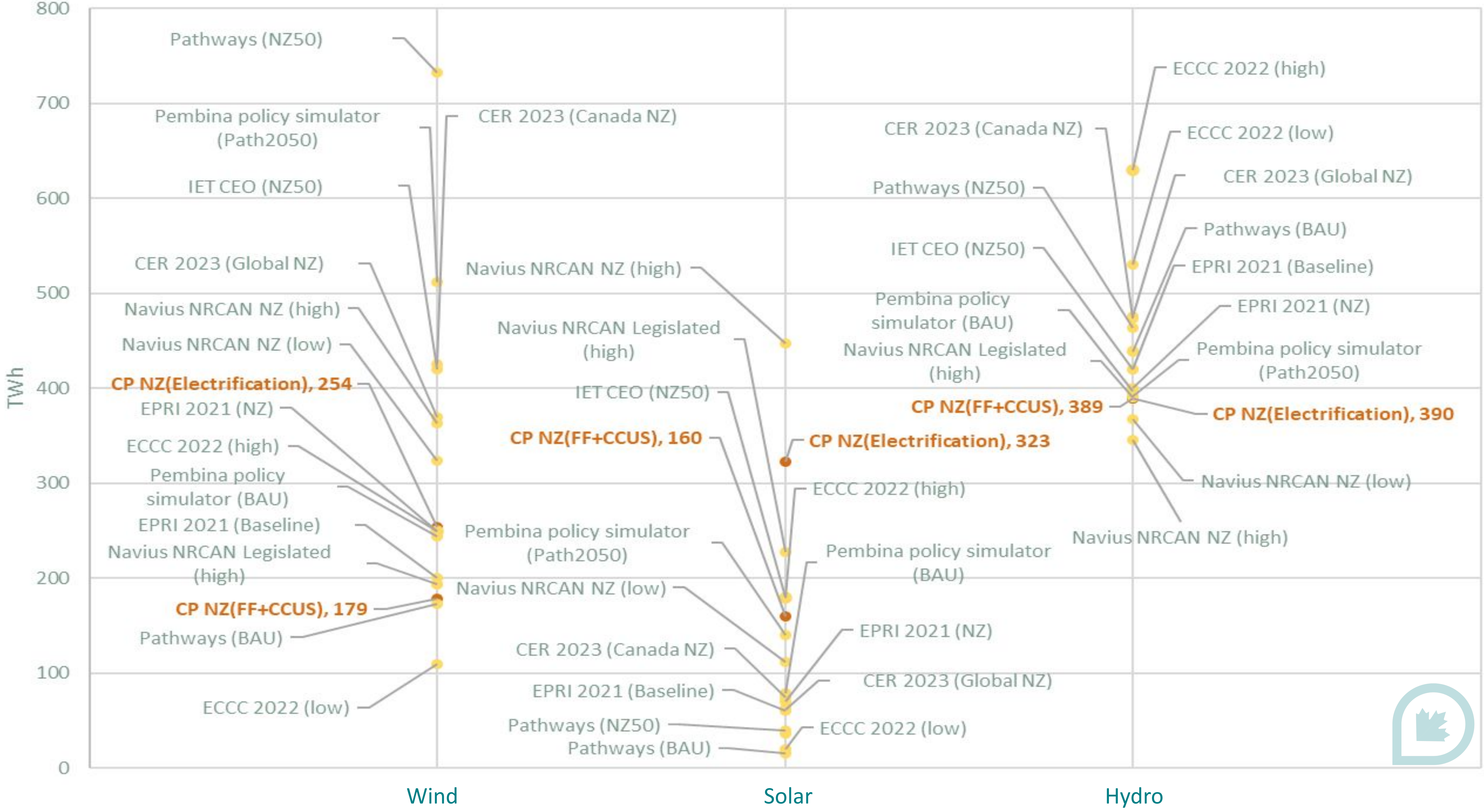
As in several other studies, **we do not expect added large hydro generation**,[4,5] nor is the potential for geothermal or offshore wind fully explored.[6]

Under the cost assumptions in the model, **new nuclear is not deployed for electricity generation** as this result is less cost-effective than other options.[7] Since our model does not consider the geographic distribution of electricity demand needs across provinces and territories, the need for off-grid solutions for Indigenous communities, remote mines and other uses would not be fully taken into account and thus might underestimate the value of small modular reactor (SMnR) deployment.[8] We note that small modular nuclear remains an avenue for further research, especially given the high cost uncertainties as well as the growing interest and investments in SMnR technology.[9]

Electricity consumption/demand and generation in 2050: comparison of studies[1]



Electricity generation from wind, solar, and hydro in 2050: comparison of studies[1]



Meeting the growing electricity demand

Considerations for electricity demand and generation

Canada's highly regionalized electricity system presents significant challenges for advancing electrification as a pillar of net zero. When we compare Canada's current electricity generation to net-zero generation projections (Slide 28), it is clear that **significant expansion is needed in all provinces** — in some cases, more than a two-fold increase (e.g., British Columbia and Alberta). Most of the province-level projections that we reviewed (Slide 29) do not project this magnitude of demand growth. Further, few utilities consider net zero as part of their planning processes.[1] We also note that for some provinces and regions, grid projections/plans are difficult to access, while plans that are publicly available tend to use their own estimation methodologies and criteria for scenario modelling, which means that there is little consistency between estimates.

The gaps illustrated in Slides 28 and 29 indicate the current lack of alignment on net-zero goals across Canada, based on initial research. Because electricity planning and regulation are largely carried out at the provincial level, coordination between provinces will be critical for deploying the level of electrification and low-carbon electricity generation needed to attain net zero.

Achieving alignment requires addressing many institutional gaps at the provincial level, as well as a more direct focus at the federal level.[2] For example, in some regions there is a lack of mandate by utilities and system operators to advance long-term climate goals. Net-zero goals may even be perceived as conflicting with regulators mandates (e.g., to protect customer interests).

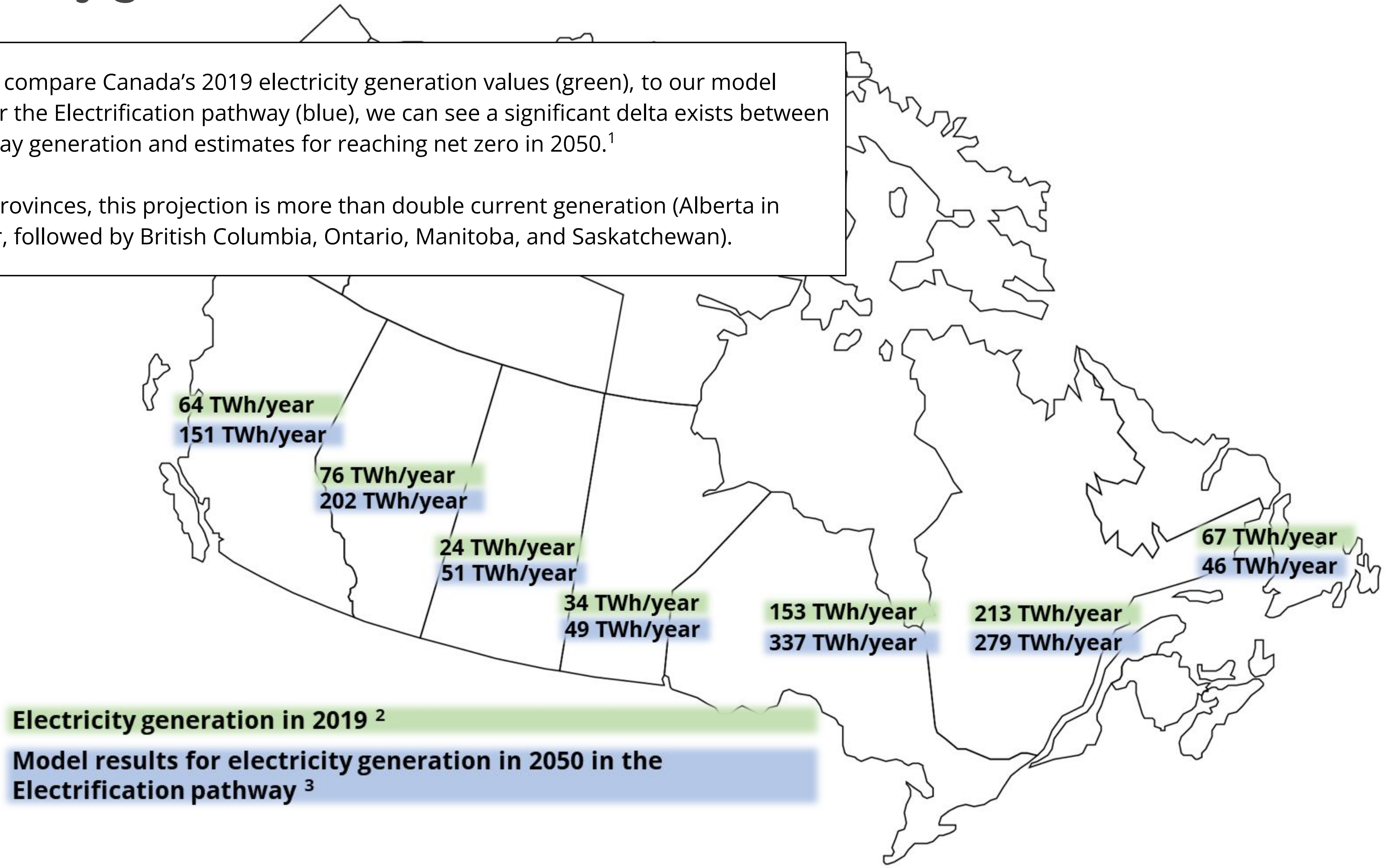
We highlight that planning for a provincial low-carbon electricity grid should not be conflated with planning for a national-level net-zero energy economy. The latter implies much greater federal-provincial and inter-provincial coordination, and significant alignment on how to best marshal Canada's assets to achieve the required outcomes.

On a regional level, this means that planning for national-level net zero requires accounting for additional drivers of electricity demand that may not typically figure into a provincial business-as-usual scenario (Slide 30).[3] An example is the electricity consumption of modelled DAC technologies, which are projected to require as much as 52 TWh in the Fossil with CCUS pathway in 2050 (as previously noted on Slide 22). In theory, the model indicates most of this DAC would be best situated in Alberta,[4] which — at a third of projected 2050 provincial generation[5] — would raise significant planning implications for fulfilling this demand.

Electricity generation in Canada vs. model results

When we compare Canada's 2019 electricity generation values (green), to our model results for the Electrification pathway (blue), we can see a significant delta exists between current-day generation and estimates for reaching net zero in 2050.[1]

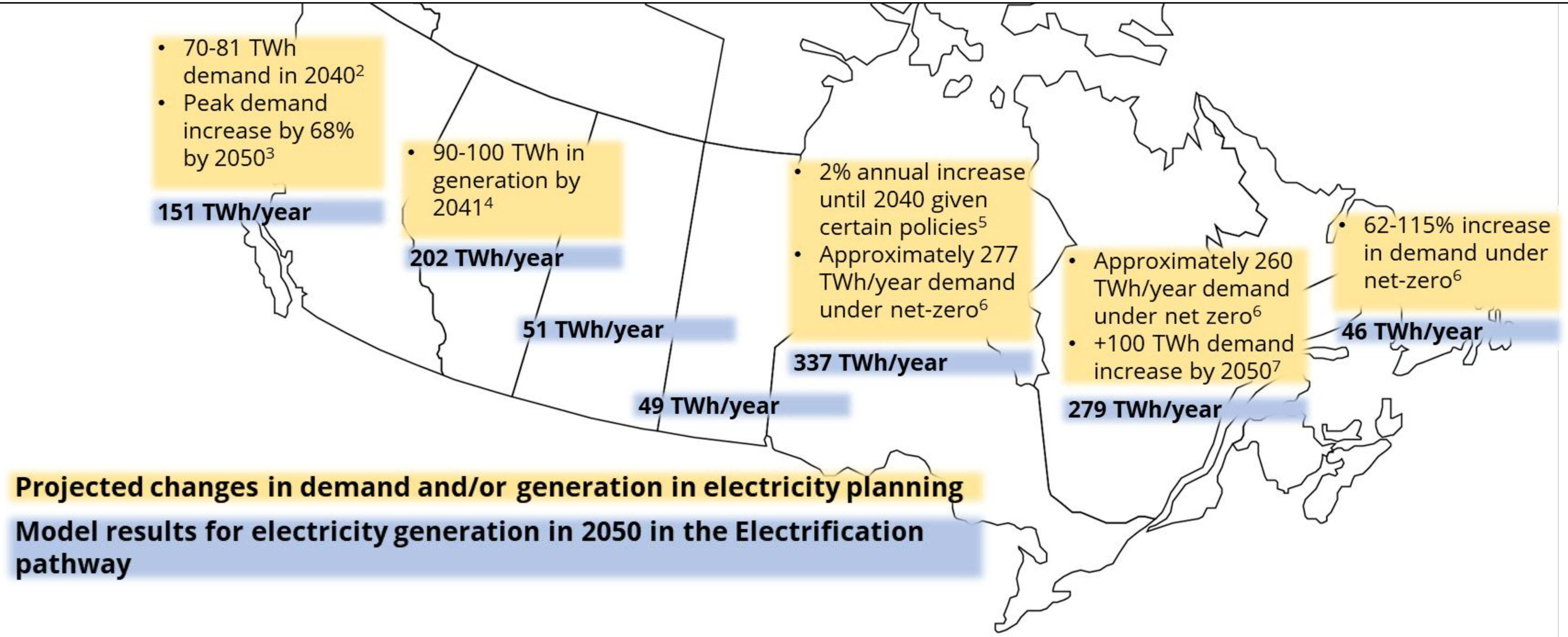
In most provinces, this projection is more than double current generation (Alberta in particular, followed by British Columbia, Ontario, Manitoba, and Saskatchewan).



Electricity generation planning in Canada vs. model results

In reviewing current plans for electrification (yellow) across the country, we see little consistency and cohesion between regions. This is reflective of the highly regionalized electricity system in Canada, as electricity regulation and planning is conducted at the provincial level. The way utilities estimate demand[1] is also highly varied across the country. Also, many provincial energy regulators do not plan for net-zero, and/or use their own criteria for scenario modeling.

To date, our modelled electricity generation requirements for net-zero are roughly in line with the available projections for Ontario and Quebec, but are much higher for Alberta. This speaks to the degree of alignment required for Canada as a whole to achieve net-zero outcomes, and emphasizes the continued importance of federal-provincial coordination for this cross-cutting sector.



Growing electricity demand

Considerations for electricity demand and generation

Our model results illustrate the emergence of several drivers of electricity demand (summarized in the table) that are new and/or amplified with net zero. The table draws out two key implications for electricity generation and grid planning for net-zero scenarios:

1. **Many net-zero measures** (including forms of carbon capture, carbon removal, and the production of alternative fuels) require electricity. These therefore **go hand-in-hand with expansion of clean electricity generation**.

2. Some emerging net-zero demand sources — such as DAC in our model — have geographic dependencies (i.e., access to geological storage) and can only be implemented in certain provinces as modelled. **Accounting for the development, siting, and operation of major net-zero technologies therefore becomes relevant to electricity planners located in these geographies.** This poses additional challenges when provincial utilities, energy regulators, and federal entities are not aligned on net-zero objectives, and underscores the imperative for coordination on efforts.

Drivers of electricity demand under net-zero compared to business-as-usual

Driver of electricity demand	Business-as-usual (BAU)	Net-zero[2]
Population growth	Likely	Likely
Economic growth	Likely	Likely
Increased electrification across economic sectors	Possible	Likely to be higher than in BAU
Implementation of more efficient end-use technologies	Possible	Likely to be higher than in BAU, reducing electricity demand[3]
Technological advancement (i.e., energy-intensive computing)	Possible	May be higher than in BAU if energy-intensive technologies are leveraged as part of net-zero strategies[4]
Implementation of direct air capture of carbon dioxide[1]	Not likely	Likely; could be high if significantly implemented
Proliferation of electricity-derived fuels (e.g., hydrogen)	Possible	Likely; could be high if significantly implemented

Next Steps

What are key areas to consider next?

Increased electrification combined with expanded low-carbon generation is generally regarded as an essential part of achieving net zero for Canada. While the model findings support this direction, a number of questions and themes arise that impact how we can advance electrification, and in particular how to better align net-zero opportunities with the planning underway on the ground. This is a major area of consideration given the need for expanded clean electricity generation we see across the board, as well as the particular geographic dependencies associated with deploying particular net-zero technologies at the scale and impact projected by the results.

Our results show that electrification is uneven across economic sectors. Our future work will examine sector-specific challenges to deploying large-scale electrification.[1] Preliminary literature review suggests that **industry subsectors** such as chemical, cement, and steel production face **technical readiness** barriers. Some industrial operations currently lack **confidence in the availability, reliability, and affordability**[2] **of electricity** at the scale needed.

Other sectors of interest include **Oil and Gas** and **Transportation**, both of which face significant challenges, such as the need for new infrastructure buildout and upgrades. In the Transportation sector, the projected climb in electricity use from a modest starting point implies the development of extensive new infrastructure, and particularly in comparison to other sectors which already have high electricity use.[3]

Our future research will look more closely at **capacity** buildout (including the role of renewables and energy storage), at national and especially at the **provincial** scales. In particular, an important part of our pending provincial work is to arrive at a better understanding of the **spatial aspects of new infrastructure buildout**, which has implications for land use, material requirements, transmission and distribution, and many other areas.[4]

Our ongoing downscaling work aims to contribute a spatial-based understanding of net-zero model results, and thus further inform the practical considerations, opportunities, and co-benefits associated with electrification expansion.

Alternative fuels: renewable natural gas

Section 4

- Overview
- Pathway results for 2050
- Comparison to other studies
- Current state of play
- Deployment gap considerations

Main points

Role of RNG as a pillar of decarbonization

Renewable natural gas (RNG) takes a large role in decarbonizing Canada's energy economy in our results, largely by replacing fossil-based natural gas as an energy source in industry and in buildings.[1] The significant amount of RNG in our modelled scenarios is in part driven by the associated opportunity for bioenergy capture and storage (BECCS), which is leveraged in the model to generate net-negative emissions. Our aggressive 2050 net-zero targets (50 Mt/year by 2050 compared to the 100 Mt/yr employed by other studies),[2] results in particularly high RNG deployment, which enables BECCS.

The amount of RNG projected in model results is much larger than many other net-zero studies and needs to be treated with caution.[3] These results also hinge on a high degree of RNG imports that can leverage existing U.S. trade and pipeline networks, though in consequence also raise energy security considerations (e.g., in terms of ensuring that enough energy resources are available for consumption). However, we suggest that the results also illustrate the potential of RNG to help achieve net-zero outcomes, especially in tandem with BECCS development to achieve net-negative emissions.[4]

Our secondary research shows that there is a **sizable gap between Canada's current RNG production vs. the RNG production and consumption** projected in our net-zero pathways. Though the model projects significant deployment of second-generation RNG, we recognize that there is uncertainty about the nascent commercial viability of wood-to-gas technology.

This said, our literature review indicates that significant **potential remains for increasing first-generation RNG production**, notably in Ontario and Quebec. This potential is not fully captured in our modelled outcomes.

Further exploration is needed to understand **where RNG may be best utilized** as an agent of decarbonization,[4] as well as abatement via BECCS.[5] For example, RNG could be used by industrial sub-sectors that face particularly high barriers to electrification, though the trade-offs between prioritizing fuels such as RNG vs. other options need to be more closely examined. Consideration of the **geographic and seasonal dynamics associated with RNG feedstocks** can help provide a more complete picture of feasibility, as well an understanding of the supporting transport, processing, infrastructure buildout, and land-management systems needed. The commercial viability and scale-up potential for BECCS is also key to explore, given the outsized impact of this technology in certain pathways and geographies.

Lastly, we suggest that paying closer attention to Canada's bio-based resources may offer an opportunity — if not an imperative — to better consider the management of residual feedstocks.[6] This is important due to the current emissions impact and fire risk of forest harvest residue (which is leveraged for RNG in our model).[7] Given the growing climate impact of Canada's forest fires (which resulted in two to three times the emissions of our entire economy in 2023), action on this front will need to be significantly accelerated and incorporated into climate policy planning.

Overview

What makes up RNG and how is it estimated?

RNG production is generally categorized into **first generation** (conventional RNG typically obtained via anaerobic digestion of organic waste and crop residues),[1] and **second generation** (such as gasification, methanization and pyro-catalytic hydrogenation of woody biomass) processes. Third-generation technologies remain in the research and development stage and are not considered in our modelling (see the table at right).

RNG production potential is understood and explored in different ways. Some studies primarily focus on the availability of physical resources, such as landfills and organic waste. Others largely examine feasibility in terms of production costs, regulations, and other socio-economic factors, and employ differing assumptions and price thresholds. Consequently there is **limited consistency** in estimates of RNG production potential across the reports we reviewed.

Typically, these reports judge that RNG production potential will hold steady over time in terms of physical resources, notwithstanding technological development, climate disruption, etc. We note that costs may decline with technological development and economies of scale, which will open up additional production potential from an economic standpoint.

Renewable natural gas: feedstocks, processing, and development stage

	First generation	Second generation	Third generation
Feedstocks	Landfill gas Organic waste Wastewater treatment Agricultural waste* Dedicated energy crops**	Forestry waste Agricultural waste* Dedicated energy crops**	Microalgae
Processing technology	Anaerobic digestion	Gasification and methanation; Pyro-catalytic hydrogenation	Direct conversion
Development stage	Marketing	Pilot projects and pre-marketing	Research and development
In model	Yes	Yes	No

* In the model, RNG from agricultural waste is treated as second generation, although some sources consider it as first generation.
** Dedicated energy crops are currently not included in our modelling.

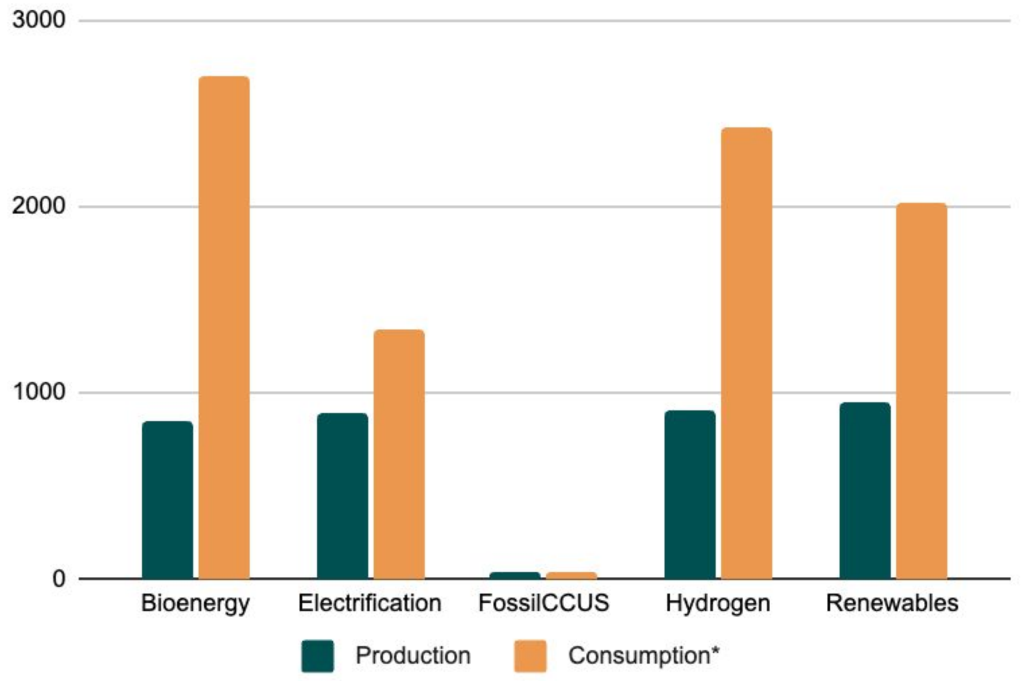
Pathways results for 2050

Examining production potential

RNG plays an important role in four of our five net-zero pathways and especially in the Bioenergy pathway, where domestic consumption reaches about 2700 PJ/year by 2050.[1] RNG becomes a significant part of the energy mix starting in 2040, and is employed to decarbonize several economic sectors including **Light Manufacturing, Buildings, and Heavy Industry**. In Heavy Industry and Light Manufacturing, where electrification potential is more challenging, RNG is used in conjunction with fossil natural gas for various industrial processes. Similarly, in Buildings, RNG helps lower emissions from the remaining (unelectrified) energy consumption. RNG use also appears in DAC, some Oil and Gas sub-sectors including petroleum refining, and in Agriculture and Construction to a minor degree. gTech also projects high RNG consumption in the Electricity sector for some pathways, which departs from the Integrated Electricity Supply and Demand (IESD) model results for this sector — this is explained further in Appendix Slide 75.

Our model results imply that 450–1900 petajoule (PJ) of RNG imports[2] would be needed in addition to 850–950 PJ of domestic production, depending on the pathway. Much of this RNG is assumed to be imported from the U.S. due to high feedstock availability in that country, and to leverage the existing energy trade relationship and established pipeline network. In our results less international climate action — including in the U.S. — is also assumed. This assumption is contradicted by the passage of the U.S. *Inflation Reduction Act* in 2022, which includes incentives for the domestic production and use of RNG.[3] This raises further feasibility and energy-security concerns associated with this import expectation.

RNG production and consumption in 2050 (PJ)



* These represent RNG consumption values from gTech. IESD reports significantly lower RNG consumption values in the Electricity sector (in some cases, several hundred PJ lower). See Appendix Slide 75.

RNG production potential

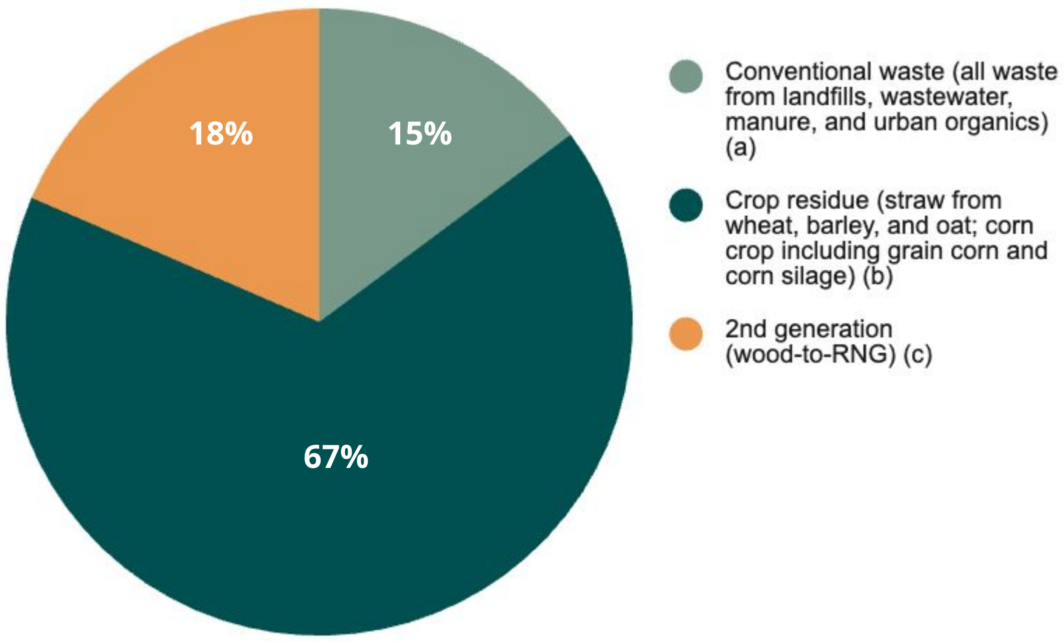
Empirical estimates

Empirical studies suggest that the vast majority of RNG production would need to come from crop residues, along with woody biomass. The figure at right shows theoretical RNG production potential in Canada. The study referenced here[1] places Canada's total theoretical RNG potential at 809 PJ/year, coming primarily from crop residue, followed by woody biomass. The study cautions that the physically and economically feasible potential of RNG however, is much lower at 155 PJ/year.

Notably, this study does not include active forest management as a potential source of feedstock. However, **other studies** (discussed on Slide 39) suggest that additional residues from active forest management can be a valuable potential input. This noted, challenges associated with the kind of large-scale RNG deployment projected by our modelling include **technical feasibility and resource limitations,** among other considerations.

Lastly, we suggest that the opportunity for active forest residue management[2] (as a part of RNG development, or other options) is of particular importance given the **growing frequency and intensity of Canadian wildfires**. In 2023 alone, wildfires produced over 1.7 billion tonnes of emissions.[3] This is more than double the emissions from human activity in 2021 (670 megatonnes [Mt]).

RNG production potential, empirical estimates[1]



Total theoretical potential: 809 PJ/year

(a) In reality, not all of this waste can be easily made available for RNG due to scale and logistical constraints.
(b) This material is largely in demand in other sectors (animal feed, ethanol, food products), and/or subject to high variability.
(c) TorchLight estimates that only about 155 PJ can be theoretically obtained from wood residues in Canada.

RNG estimates in Canadian net-zero studies

Our results show higher production and consumption of RNG relative to other Canadian net-zero studies where RNG also appears as a key part of the energy system (dark green). This is largely attributable to the more demanding net-zero constraint we have explored in our work. Other studies mention RNG as a bioenergy option or a part of BECCS (light green); or do not mention RNG at all (blue). Notably, none of these studies examine the implications of RNG in depth, even when high consumption estimates are shown. The systematic presence of RNG in modelled energy systems suggests that options to accelerate the technology readiness of RNG and BECCS may be an opportunity for Canada, alongside other possibilities for the optimal use of bio-based feedstocks. As noted, the role of active forest residue management may become of increasing importance in terms of helping to address Canada's growing forest fire emissions.

Canadian Climate Institute, Canada's Net Zero Future 2021	RNG is consumed in all five net-zero scenarios, to a maximum of 1,534 PJ in 2050.
Navius Research, Canada Energy Dashboard 2023	RNG consumption in net-zeo pathways, up to 1,270 PJ in 2050
Environment Climate Change Canada, Exploring Approaches for Canada's Transition to Net-Zero Emissions 2022	RNG is modelled as a backstop fuel, with final total consumption reaching around 400 PJ in 2050.
Canada Energy Regulator, Canada's Energy Future 2023	RNG is blended (along with hydrogen) with natural gas. Blending is limited to 10-15% of natural gas content by 2050 due to feedstock constraints.
Institut de L'Energie Trottier, Canadian Energy Outlook 2021	RNG is included as part of an extensive analysis of bioenergy/biomass/biofuel production and use.[1]
Canadian Climate Institute, Bigger, Cleaner, Smarter 2022	Does not analyze RNG specifically, however biogas and BECCS are discussed.
Electric Power Research Institute, Canadian National Electrification Assessment 2021	Does not discuss RNG, however BECCS and bioenergy are mentioned generally as low-carbon alternatives.
David Suzuki Foundation, Shifting Power 2022	Does not mention RNG
Institut de L'Energie Trottier, On the way to net-zero 2021	Does not mention RNG
Clean Energy Canada, Decarbonizing Industry in Canada and the G7 2023	Does not mention RNG

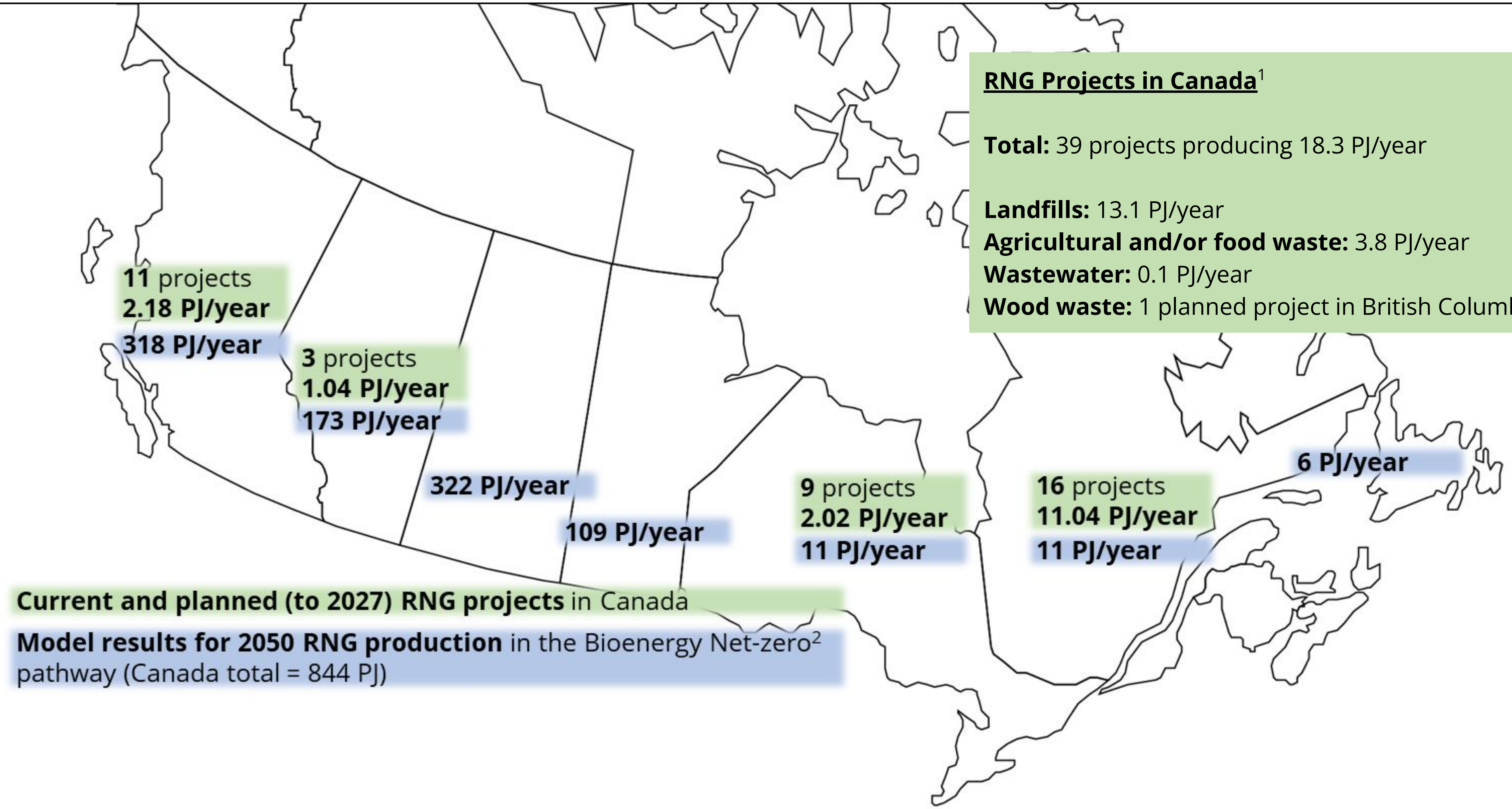
RNG projects in Canada vs. model results

When we look at current RNG across Canada, we see a total of 39 operating or planned projects producing a **total of 18.3 PJ/year,** most of which are landfills. This indicates that **current RNG production is hundreds of PJ lower** than what the majority of our modelled net-zero pathways project for 2050. These estimates particularly diverge on the west coast and in the prairies.

RNG Projects in Canada[1]

Total: 39 projects producing 18.3 PJ/year

Landfills: 13.1 PJ/year
Agricultural and/or food waste: 3.8 PJ/year
Wastewater: 0.1 PJ/year
Wood waste: 1 planned project in British Columbia for 1.2 PJ/year



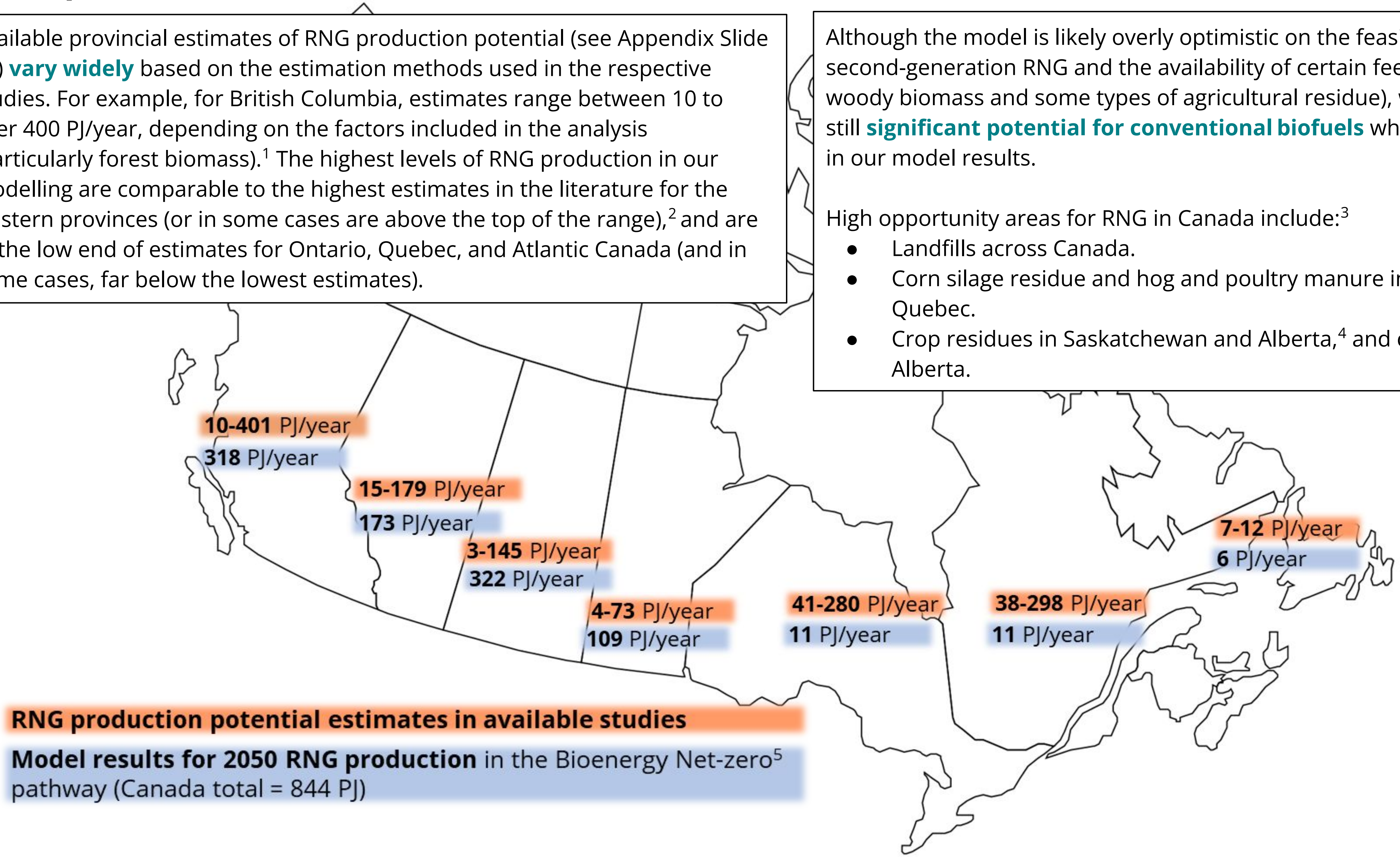
RNG potential in Canada vs. model results

Available provincial estimates of RNG production potential (see Appendix Slide 83) **vary widely** based on the estimation methods used in the respective studies. For example, for British Columbia, estimates range between 10 to over 400 PJ/year, depending on the factors included in the analysis (particularly forest biomass).[1] The highest levels of RNG production in our modelling are comparable to the highest estimates in the literature for the western provinces (or in some cases are above the top of the range),[2] and are at the low end of estimates for Ontario, Quebec, and Atlantic Canada (and in some cases, far below the lowest estimates).

Although the model is likely overly optimistic on the feasibility of second-generation RNG and the availability of certain feedstocks (including woody biomass and some types of agricultural residue), we note there is still **significant potential for conventional biofuels** which is not reflected in our model results.

High opportunity areas for RNG in Canada include:[3]

- Landfills across Canada.
- Corn silage residue and hog and poultry manure in Ontario and Quebec.
- Crop residues in Saskatchewan and Alberta,[4] and cattle manure in Alberta.



Modelling of RNG

The **model accounts for many aspects of RNG production and consumption,** including different production pathways and feedstock sources. Forest and agricultural residues are modeled as a fixed percentage of the forestry and agricultural sectors and do not include energy crops, so in some sense represent conservative estimates. Other aspects of our RNG modelling that merit further consideration and research include: technology development, feedstock supply variability, socio-economic aspects such as land management, geographic considerations, and other factors (see the table below).

Challenges and constraints with RNG	Representation in Navius model
Wood gasification and pyrolysis technologies are **not yet in commercial stage**.[1]	*Assumed to be available in the future.*
Limited amounts of wood fibre are available. In B.C., almost no mill residue is available for new projects. Roadside residue is partially already used by pulp and pellet mills. High costs of retrieving fibre beyond certain distance from road.[2]	*Forest residue is modelled as a fixed percentage based on activity in the forestry sector.*[3]
Tenure-based management system of Canada's publicly-owned forests adds challenges to the security of woody feedstock.[1]	*Not represented.*
Corn stover is readily available in Ontario and Quebec, but **varies dramatically** in the prairies.[1]	*Regional differences based on feedstock availability, energy prices, trade and demand are accounted for, but not the geographic detail beyond that of the aggregate provincial scale.*[4]
Much straw (wheat, barley, oats), corn grain, and corn silage are **used in other sectors** (i.e., animal feed) and are subject to significant **annual supply variability.**[1] Such feedstocks can be costly to collect and transport, and require extensive pretreatment.[2]	*Agricultural residue is modelled as a fixed percentage based on activity in the agricultural sector (25% of yield). Annual supply variability not represented.*[4,5]
Geographic considerations: some resources are too far from pipelines to warrant the cost of upgrading.[1]	*Not represented. The availability of pipelines is considered for RNG production and trade between regions, but not within a province.*
Regional differences in RNG production costs due to differing resource availability (e.g., landfill gas at \$15.60/GJ vs. gas produced from southwestern Ontario corn silage at \$41.60/GJ).[1]	*Regional differences are accounted for but not geographic detail beyond the aggregate provincial scale.*[4]
Feedstocks may be **better or alternatively used f**or other value-added bioproducts (such as biopharmaceuticals and biochemicals).	*The advanced bioeconomy is not represented.*

Deployment gap considerations

What are key areas to consider next?

Although the scale of our RNG results need to be interpreted with caution (given the uncertainty regarding second-generation RNG production, feedstock supply, import expectations, and other considerations noted), we suggest that the possibility of leveraging RNG production to achieve net zero merits further examination in Canada, alongside other technologies earlier in the commercialization phase (like direct air capture [DAC]).

Our next steps will therefore aim to better understand the feasibility of RNG deployment from a sectoral, as well as regionalized, perspective. This includes identifying the most appropriate **sector-based applications of RNG as part of a regional deployment approach.** In doing so, we will examine RNG alongside other potential decarbonization options to evaluate the various benefits and tradeoffs associated.

Further developing the regional perspective is particularly crucial for RNG deployment given the specific regional dynamics and geographic constraints[1] associated with RNG production and use. Given the remaining potential for conventional RNG production in certain regions, and the considerable uncertainty regarding second-generation RNG, work is needed to understand **where RNG development may make sense** to pursue.[2]

The role of BECCS in realizing net-negative outcomes is also paramount and tied to geography (e.g., CO_2 storage potential). Downscaling our RNG and associated BECCS modelling results can help further illuminate key spatial constraints faced by feedstock suppliers and production facilities, and the opportunities for CO_2 storage. This will help to inform a more complete understanding of the feasibility and opportunities for BECCS associated with our results.[3]

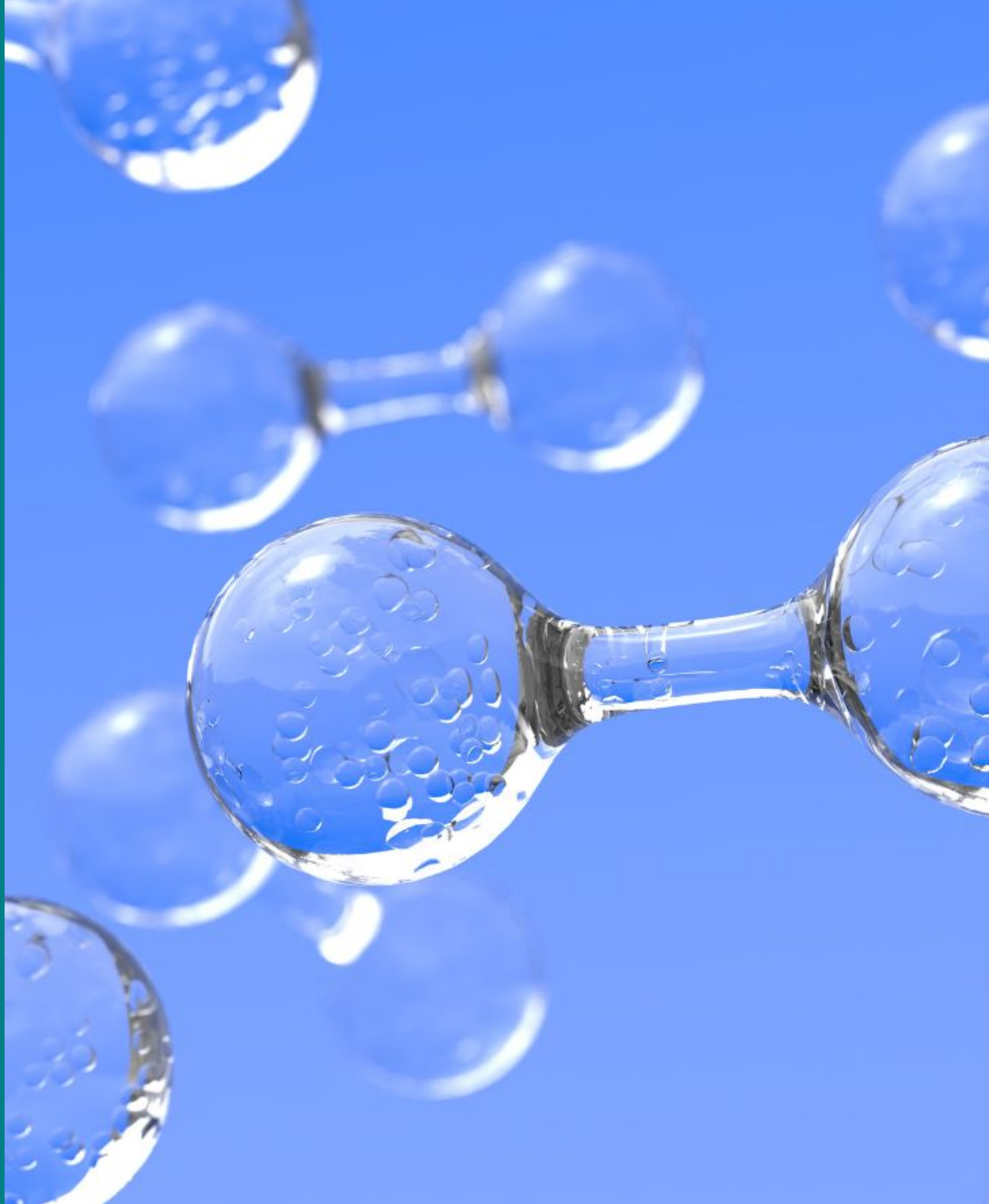
Lastly, we recognize it is important to situate RNG as part of a **holistic vision of a bioeconomy**, rather than as an isolated fuel substitute within the energy system (as it is currently conceived in the model). This includes the consideration of **other potential uses** for feedstocks, such as energy from solid biomass, liquid biofuels, and other bioproducts. These applications may be more advantageous in terms of emissions reductions or other potential benefits in some cases.

We conclude that optimizing Canada's biomass assets could be a crucial part of the transition towards net zero, with RNG potentially playing a key role in specific sectors and especially in combination with carbon sequestration. We also suggest that the active management of forest harvest residues will become of increasing importance in order to address the outsize impacts of Canada's forest fires on global emissions.

Alternative fuels: hydrogen

Section 5

+ Overview
+ Pathway results for 2050
+ Comparison to other studies
+ Current state of play
+ Deployment gap considerations



Main points

Role of hydrogen in decarbonization

Canada currently produces around 3 megatonnes (Mt) (360 petajoules [PJ]) of hydrogen as a feedstock for chemical and industrial processes through unabated steam methane reforming (SMR). Shifting current production toward cleaner options represents a sizable opportunity for decarbonization.[1] In this analysis, we focus on a different role for hydrogen as an energy carrier (fuel alternative to petroleum and natural gas).[2] This is the form of hydrogen that is of most relevance to developing a hydrogen-based economy.[3]

In our modelling results, hydrogen as an energy carrier makes up 2%–5% of total energy consumption across the economy in 2050 (up from a negligible amount currently), largely as a result of hydrogen being outcompeted by other fuels. The highest deployment occurs in our Hydrogen pathway, which is most conducive to hydrogen scale-up. Our results fall in the low-to-medium range of total energy consumption when compared to other Canadian net-zero studies (which estimate from 4%–9%).[4] Our results, although modest, still imply the development of significant new transportation and distribution capacity.

These findings contrast with the Federal Hydrogen Strategy,[5] which estimates that hydrogen can deliver up to 30% of Canada's end-use energy by 2050. The Federal Hydrogen Strategy is also significantly more optimistic on hydrogen compared to available provincial strategies, and estimates that hydrogen deployment can abate up to 190 metric tonnes of carbon dioxide equivalent ($MtCO_2e$) (transformative scenario), while provincial abatement estimates reach around 75 $MtCO_2e$.

Hydrogen production via electrolysis using renewable energy ("green" hydrogen) is a prominent production strategy anticipated by many provinces and a model result seen in our high electrification pathways. So-called "blue" hydrogen (produced via SMR/ATR[6] with CCUS) has been of interest mainly in Alberta, Saskatchewan, and northwestern British Columbia. This production process plays a prominent role in our Fossil with CCUS and Hydrogen pathways.

In our results, about 90% of final hydrogen consumption occurs in the transportation sector, with the remainder used by utilities for blending with natural gas.[7] This aligns with the federal and provincial strategies, which include developing refuelling hubs and natural gas-hydrogen blending by 2030. This aspect of end-use and distribution is an important area to explore in hydrogen research, given the major technical challenges associated with new infrastructure development.[8]

We recognize the importance of continued research into hydrogen as a potential alternative fuel, despite its relatively minor role in our net-zero results. We further stress that better understanding is needed of the potential climate impacts of hydrogen leakage and risks of scaling up hydrogen for use as a fuel.

Overview

Canada produces about 3 million tonnes (360 PJ) of hydrogen annually.[1] Less than 1% is used by utilities or for transport; the rest is for use as an industrial and chemical feedstock.[2] Current hydrogen manufacture relies on high-emitting steam methane reformation (SMR), termed "grey hydrogen",[3] which is accounted for and reported as natural gas in Canada's energy balance.[4]

There are several keystone technologies anticipated in federal and provincial strategies to evolve this production pathway. For example, the primary focus of the Federal Hydrogen Strategy is deployment of hydrogen production via electrolysis ("green hydrogen") and SMR with carbon capture utilization and storage (CCUS) ("blue hydrogen").

Although green and blue hydrogen are the main focus of most Canadian developments, other methods of production are also modelled in our work, including natural gas pyrolysis and biomass gasification.

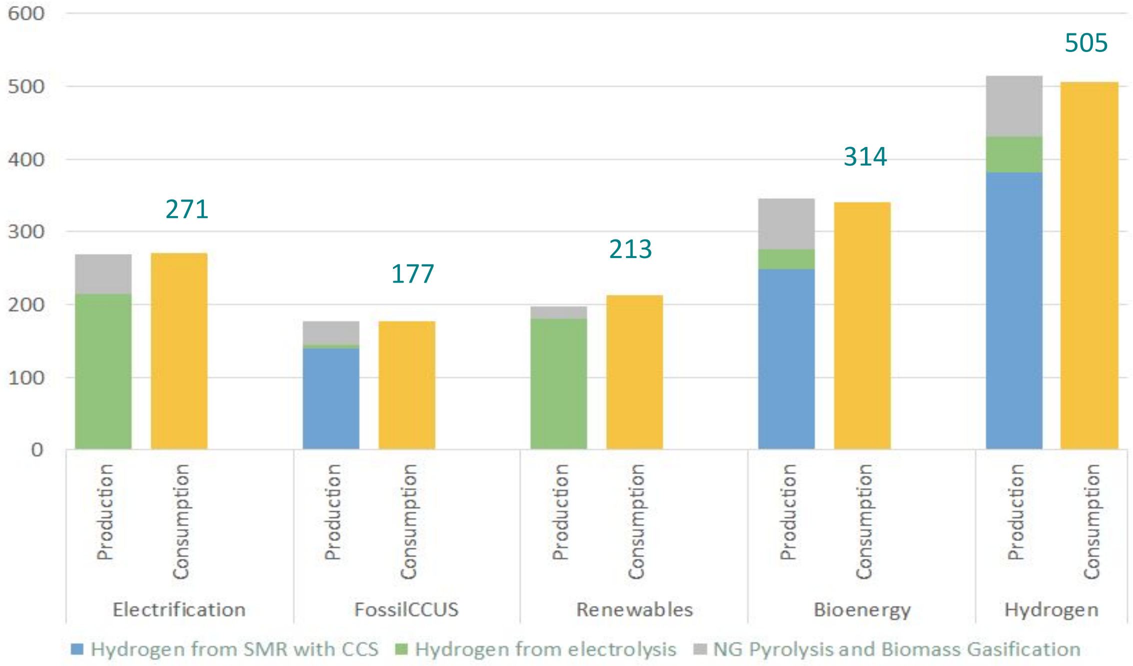
Steam methane/autothermal reforming + CCUS hydrogen	Electrolysis hydrogen
Definition: Steam methane reforming and autothermal reforming (SMR, ATR) are processes that convert natural gas into hydrogen, with CO_2 as a byproduct that can then be captured. Termed "blue" hydrogen. **Advantages** A high-purity CO_2 stream allows for higher capture rates, which can be monetized through storage accreditation. **Drawbacks** Requires access to carbon sequestration infrastructure.	**Definition:** Use of electricity to split water into hydrogen and oxygen. Termed "green" hydrogen if produced using renewable energy. Renewed interest in nuclear as an energy source (so-called "pink hydrogen"). **Advantages** No underground storage necessary. Can be produced during low grid usage, though the carbon intensity will vary depending on the electricity grid profile. **Drawbacks** High cost ($/kg) compared to SMR and ATR, but cost is projected to decrease by 2030.
Natural gas pyrolysis	**Biomass gasification**
Definition: Future technology that converts methane into hydrogen and solid carbon. Termed "turquoise" hydrogen. **Advantages** Produces solid carbon as a byproduct, which has utilization potential and is easier to manage than gaseous CO_2. Can occur underground at the natural gas point source. **Drawbacks** Not commercially available.	**Definition:** Type of reforming plant that uses biomass as a feedstock instead of natural gas. **Advantages** Can be carbon-neutral or carbon-negative when underground storage is incorporated. Underground storage optional. **Drawbacks** Limited by feedstock availability.

Pathway results for 2050

What role could hydrogen play in 2050?

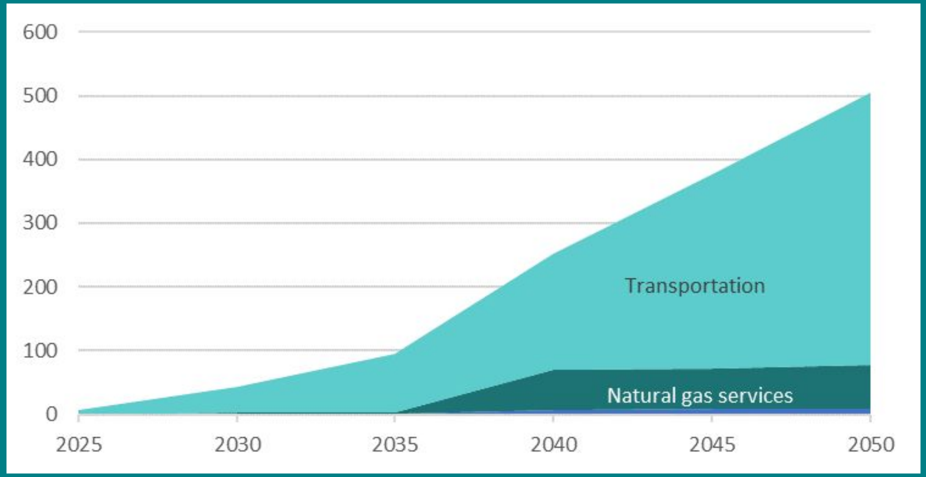
Hydrogen is currently used as a feedstock for industrial applications and is reflected in the model as a feedstock used by multiple sectors.[1] In our analysis, hydrogen is explored in its role either as a transport fuel or as blended into natural gas services.[2] Hydrogen for a fuel appears primarily in heavy duty vehicles in the transportation sector, and in other sectors to a lesser extent (e.g. mining, agriculture, light manufacturing and oil and gas). When blended with natural gas, hydrogen is consumed in any sector that uses natural gas for heating or electricity generation.

Hydrogen production and consumption in 2050 (PJ)



This approach results in **hydrogen making up 2%–5% of total energy consumption in 2050**. The highest deployment of hydrogen occurs in our Hydrogen pathway, which models input costs most conducive to its development;[3] however, even in this pathway we still see hydrogen being outcompeted by other fuels. In high-electrification pathways such as Electrification and High Renewables, green hydrogen production predominates, while other pathways favour the production of blue hydrogen (see the figure at left).

Estimated end-use consumption (PJ) of hydrogen in Canada, Hydrogen net-zero pathway



Although our results indicate relatively modest consumption of hydrogen as an energy vector, we note that **significant infrastructure buildout for distribution and refuelling would be required** to realize this expectation. Given that 100 PJ of hydrogen would require an estimated ~1 to 2 million tube trailers to transport,[4] even our most modest projections for hydrogen deployment (177 PJ/yr) suggest that new pipeline infrastructure would be required. The technical challenges, climate implications,[5] and cost[6] associated with large-scale buildout should be carefully evaluated, especially if other decarbonization options are available.

Comparison to other studies

Our 2050 hydrogen consumption estimates range from conservative to average compared with other Canadian net-zero studies. Most other studies also project low production of hydrogen for use as an energy carrier (Pathways, Canada Climate Institute dashboard, Institut de l'énergie Trottier, Navius NRCAN NZ), **ranging between 4% and 9%** of total energy consumption — see the figure at right.[1]

The Federal Hydrogen Strategy, the Transition Accelerator, and the Canada Energy Regulator (Global NZ) all report higher values, partly because industrial feedstock applications are included in their production estimates. The Transition Accelerator's scenario also includes global exports.[2]

Notably, the Federal Hydrogen Strategy's "transformative" scenario and the Transition Accelerator's "total market" scenarios are significant outliers, as they set out to explore how hydrogen can form part of a major shift in the energy economy.

The Federal Hydrogen Strategy's "transformative" scenario, for example, suggests that as much as 30% of the economy could be fuelled by hydrogen by 2050.[3]

Hydrogen in net-zero and other estimates[4]

State of play

The table at right illustrates the status of hydrogen projects in Canada based on production process. The future vision for hydrogen varies by region, however anticipates a departure from Canada's current production method for hydrogen, which is based on SMR without CCUS.

On the following slide we present an overview of federal and provincial hydrogen plans underway across Canada. Most provinces are focused on producing electrolysis (green) hydrogen using various renewables (wind, hydro, nuclear), despite the current high costs anticipated with this production process. Northwestern B.C., Alberta, and Saskatchewan are opting for blue hydrogen strategies so as to leverage their available CO_2 storage infrastructure.

The ambitious estimates[1] presented in the Federal Hydrogen Strategy (which include feedstock hydrogen) depart from provincial planning estimates. Federal estimates of 45 $MtCO_2$ of emissions abatement from hydrogen in 2030 are well above the 25 Mt anticipated by the provinces.[2] By 2050, the provinces are estimating 75+ $MtCO_2$ of abatement,[3] which is less than half of the 190 $MtCO_2$ anticipated by 2050 in the federal plan. This said, there are common elements across strategies with respect to implementation, such as:

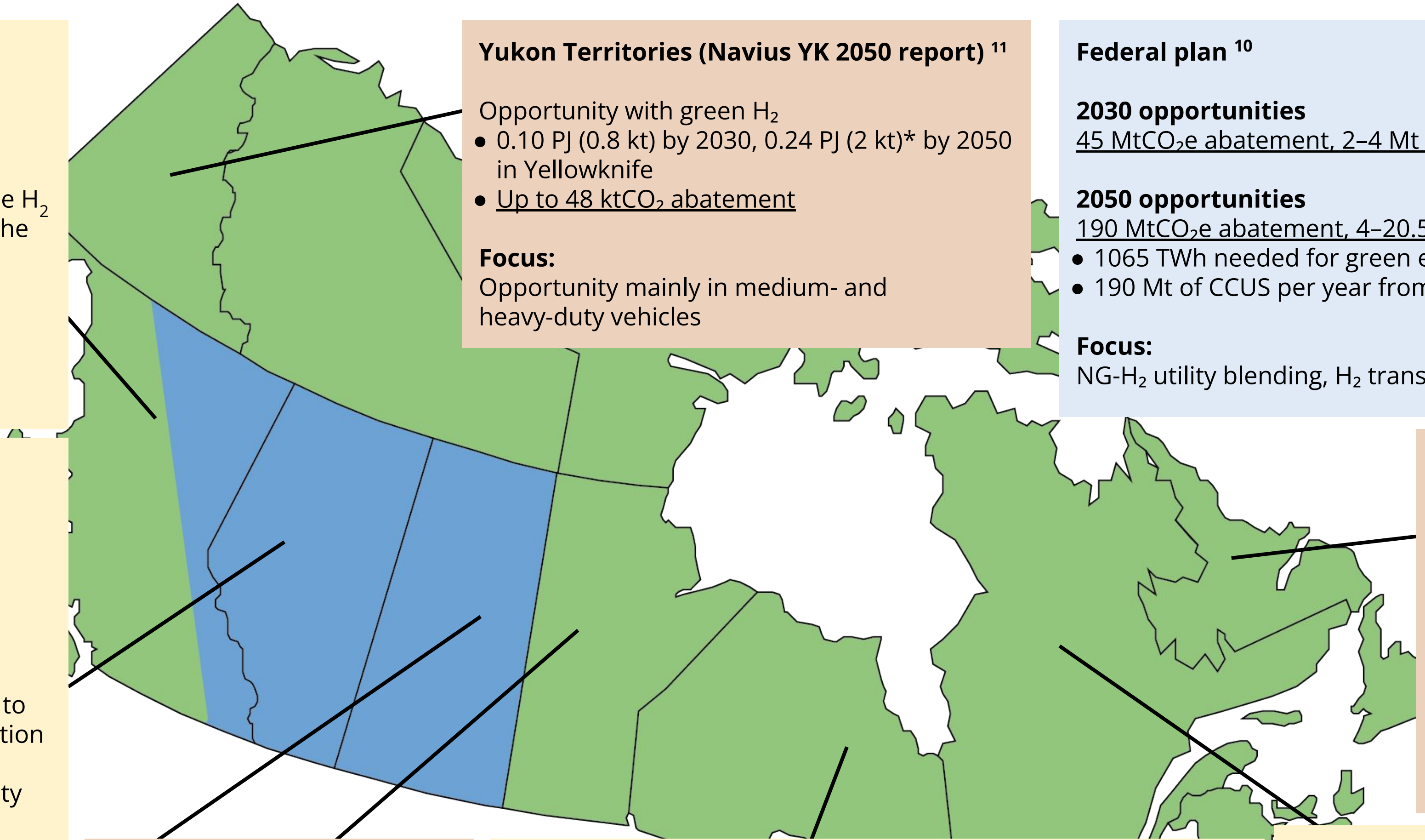
- Natural gas-H_2 utility blending and hydrogen-specific pipelines for utilities.
- Refuelling hubs for heavy-duty vehicles and at ports;[4] and applications for fuel cell EVs (e.g., forklifts), and in mining.[5]
- Feedstock switching of industrial and chemical applications from grey to blue, or from grey to green. This is the largest portion of anticipated abatement.

Hydrogen: production and Canadian projects

Production process	Canadian production/projects (under construction or active)[6]
Grey (SMR without CCUS)	• Currently three million tonnes per year, primarily for industrial use
Blue (SMR with CCUS)	• Shell Quest project at the Scotford upgrader near Edmonton, Alberta, captures about 1 $MtCO_2$/year • Air Products' ATR hydrogen facility under construction in Alberta's industrial heartland, set to launch in 2024[7]
Green (Electrolysis with renewables)	• Air Liquide's 20 MW plant in Becancour, Quebec, produces up to 8.2 tonnes of hydrogen per day • A 2.5 MW power-to-gas project in Markham, Ontario, produces 400,000 kgH_2/year, some for blending into the natural gas distribution network
Pink (Electrolysis with nuclear)	• Feasibility study planned at the existing Bruce Nuclear Generating Station in Ontario[8]

Hydrogen planning in Canada

*Maximum values



British Columbia — Roadmap 2050 [1]

Opportunities for green H_2 production (short-term) from hydropower (southeast) and blue H_2 near oil facilities (northwest) in the mid-term

7.2 $MtCO_2e$ of abatement
- Transportation (60%)
- Synfuels (25%)
- NG replacement (15%)

Alberta — Roadmap 2030 [2]

Blue hydrogen opportunities to upgrade NG with CCUS

Focus:
In a transformative scenario (14 $MtCO_2e$ abated)
- 12 $MtCO_2e$ from adding CCUS to existing grey hydrogen production from chemical and oil plants.
- 15% H_2 blend in utilities capacity and 200,000 households
- 10% diesel vehicle shift.
- 10 Mt (1200 PJ) H_2 by 2050 (for exports)

Saskatchewan — interested [3]

Focus:
Developing blue hydrogen hubs and *in-situ* upgrading (NG pyrolysis), with active projects

Yukon Territories (Navius YK 2050 report) [11]

Opportunity with green H_2
- 0.10 PJ (0.8 kt) by 2030, 0.24 PJ (2 kt)* by 2050 in Yellowknife
- Up to 48 $ktCO_2$ abatement

Focus:
Opportunity mainly in medium- and heavy-duty vehicles

Federal plan [10]

2030 opportunities
45 $MtCO_2e$ abatement, 2–4 Mt H_2 of demand (~240–480 PJ)

2050 opportunities
190 $MtCO_2e$ abatement, 4–20.5 Mt of H_2 demand (~480–2400 PJ)*
- 1065 TWh needed for green electricity by 2050 **OR**
- 190 Mt of CCUS per year from blue hydrogen

Focus:
NG-H_2 utility blending, H_2 transport hubs

Maritimes — interested [7,8,9]

Newfoundland 2030 roadmap pending; advancing wind hydrogen projects

Focus:
- NB: 200 MW (~6 PJ)* Port Hub
- PEI: Green hydrogen production by 2025
- NS: Two green hydrogen proposals, based on wind

Manitoba — interested [4]

Has implemented a hydrogen steering committee, active since 2003

Focus:
Two current projects for green hydrogen hubs, under construction

Ontario — Roadmap 2030 [5]

- Green hydrogen from hydropower.
- 140 MW (~5 PJ)* of installed capacity planned by 2030
- Renewed interest in generation from nuclear ("pink hydrogen")
- Recognizes opportunity to abate 50 $MtCO_2e$ by **2050**

Focus:
Industrial feedstocks, fertilizer, warehouse FCEVs and NG-H_2 blending

Quebec — Roadmap 2030 [6]

- Opportunities with green H2 from hydropower as well as biomass gasification
- Recognizes opportunity to abate 4 $MtCO_2e$ by 2030

Focus:
Switch from grey to green hydrogen as a feedstock for chemicals and heavy industry

Deployment gap considerations

What are key areas to consider next?

One of the key challenges with widespread adoption of hydrogen as an energy carrier is that it entails substantial buildout of new infrastructure.[1] While the gTech model accounts for variable inter-provincial transportation costs, it does not represent variable intra-provincial transportation costs (e.g., pipelines, truck transport, etc.).[2] Exploring the dynamics and implications of end-use distribution is an important area under exploration in Canada, especially in sectors that require hydrogen feedstocks, or that gain additional benefits from fuel switching.[3]

Our results align with other emerging research exploring the potential for hydrogen as a clean fuel, including in the transportation sector (particularly for bus, rail, aviation, and marine freight). As discussed, work is underway by Natural Resources Canada[4] and various provincial agencies to explore pathways to **maximize hydrogen-based emissions reduction with focused infrastructure buildout** (e.g. centralized *in-situ* refuelling hubs for high vehicle traffic zones, such as ports and trucking corridors).

As noted, most studies — as well as the federal strategy and provincial roadmaps — highlight the opportunity for emissions reduction in switching away from grey hydrogen to cleaner forms of production (green or blue). Strategies also recognize the emergence of a potential **global market for hydrogen.**[5] With some countries being particularly optimistic about hydrogen as a clean energy source, hydrogen could represent an opportunity for clean fuel market export. This said, there are significant cost and energy efficiency challenges with shipping hydrogen, as well as burgeoning competition from the United States, which has among the most generous subsidies on offer globally for clean hydrogen production.[6]

Other notable work in the hydrogen economy sphere includes a paper series by the Transition Accelerator[7] that seeks to develop a **regionalized perspective** on the **production and use of clean hydrogen**, as well as identify **sector-specific opportunities** (the role of hydrogen in the decarbonization of steel production is a notable example).[8]

We recognize the importance of continued research into hydrogen as a potential alternative fuel, however note its relatively minor role in our net-zero results. We further stress that better understanding is needed of the potential climate impacts of hydrogen leakage[9] and risks of scaling up hydrogen for the transportation-based end-uses projected in our results.[10]

Carbon capture and removal: carbon capture utilization and storage

Section 6

+ Overview
+ Pathway results for 2050
+ Comparison to other studies
+ Current state of play
+ Deployment gap considerations

Main points

Role of CCUS in decarbonization

The carbon capture, utilization and storage (CCUS) sector is under active development in Canada, principally in Alberta and Saskatchewan. Up to 4 megatonnes (Mt) a year of CO_2 is currently captured and geologically stored, and used primarily for enhanced oil recovery (EOR). Infrastructure under development is focused on allowing CO_2 emitters to transport CO_2 via pipeline to centralized wells that inject CO_2 into deep storage. This "hub" model is supported by existing industrial carbon pricing and emission offset credits, which allows operators to generate revenue streams for CCUS operations.[1]

CCUS is deployed in our net-zero simulations to abate emissions from persisting fossil fuel use in the economy, and/or in combination with biofuels to achieve net-negative emissions through bioenergy with carbon capture and storage (BECCS). Compared to other studies, our results range from low to high, depending on the net-zero pathway explored. In our model results, CCUS is projected to be an integral part of the economy in 2050, although the magnitude of its deployment differs across pathways (from 89 Mt/yr in High Renewables to 206 Mt/yr for Bioenergy).

In all pathways, CCUS enables decarbonization of key industrial sectors, including cement and hydrogen manufacturing, electricity generation, as well as select sub-sectors in oil and gas.

When bioenergy development is coupled with CCUS (BECCS), this presents a net-negative emissions option that is especially prominent in high-RNG pathways such as Bioenergy and Hydrogen.

Only five provinces have access to onshore[2] underground CO_2 storage, which is reflected in our modelling results for CCUS. Northwestern B.C., Alberta, and Saskatchewan have access to well-studied basins with high-capacity permanent saline storage, as well as roadmaps and policy focused on development. Ontario has access to a low-capacity storage basin and is developing a CCUS roadmap. Quebec has potential access to a basin but is at an earlier stage of development interest, with some private sector activity underway.[3]

Our early downscaling work suggests that there is significant potential for near-term CCUS expansion in Alberta, pending continued buildout of distribution infrastructure and injection wells. In other provinces such as Ontario, CCUS faces added constraints due to limited storage basin capacity. Furthermore, CCUS implementation will vary by province in terms of its specific industry applications, which bears further consideration in planning related to this sector.

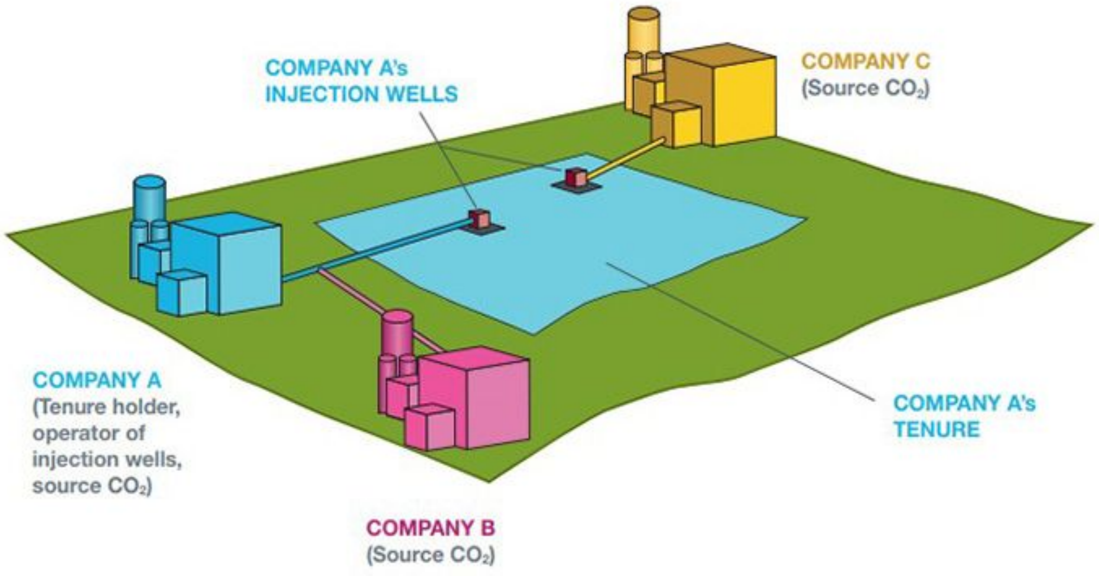
Overview

CCUS infrastructure in Canada

CCUS infrastructure in Canada consists of (1) capture technology deployed at the point source,[1] (2) transport of the captured CO_2 (typically by pipeline), and (3) injection sites/technologies that transfer the CO_2 to deep underground storage.[2] Currently, the main commercial utilization of captured CO_2 is for enhanced oil recovery (EOR).[3,4]

As this is an area we are exploring for mapping analysis (some preliminary results of which are shared in this report), it is of value to describe technical developments regarding CCUS deployment in Canada. In essence, distinct infrastructure and implementation strategies are required for different aspects of CCUS deployment, including capture systems at the point source, pipelines for transport, and wells for injecting CO_2 underground. Carbon storage is especially difficult to develop, as it is expensive to drill and monitor injection wells.[5] For this reason, there is a growing interest in developing CO_2 storage using an "open hub" model.

Alberta, for instance, is actively pursuing this model and has to date approved 24 evaluation permits to explore feasibility.[6] This model involves a CO_2 injection site that is run by a single operator, which allows nearby facilities to focus on capturing and shipping their captured CO_2 to the injection site. In suitable cases, emitters can run a connection to an existing CO_2 pipeline that goes to an injection site.



Open hub model example (Government of Alberta[6]): Company A holds tenure on the injection site area and operates the injection wells. Companies B and C transport their captured CO_2 via pipelines to Company A's injection wells.

State of play

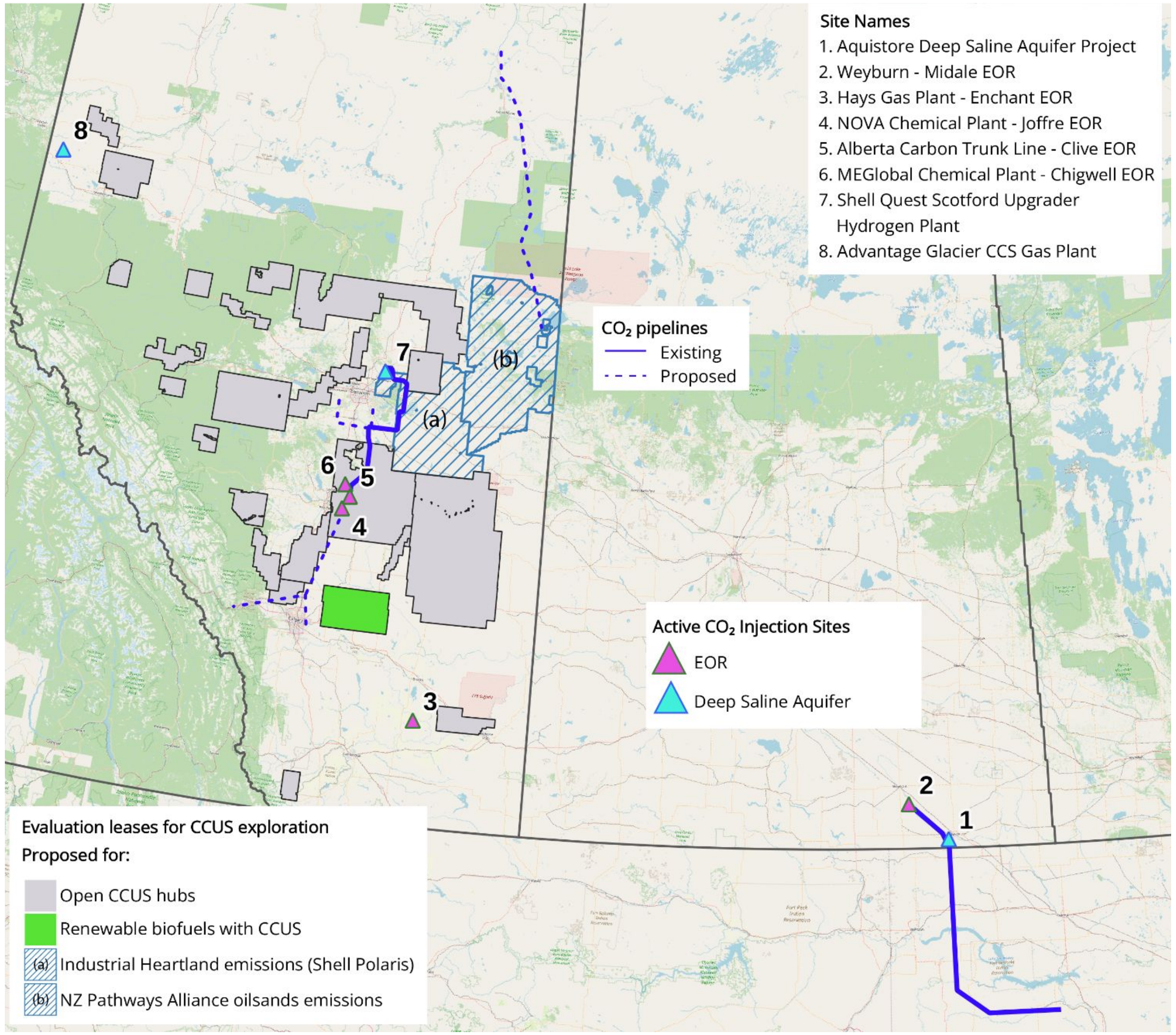
What makes up CCUS in Canada?

Currently there is about 4 megatonnes (Mt) of installed CCUS in Canada[1] (eight injection sites and two pipelines, as shown in the figure at right). The federal government's Carbon Management Strategy expects at least 16 Mt a year of CCUS will be implemented by 2030.[2] Provinces are also in various stages of CCUS planning, with differing levels of interest and available geological resources (see Slide 54).

Most of Canada's **existing and anticipated carbon capture infrastructure is in Alberta** because the province has a wealth of professionals with subsurface knowledge, standardized regulation,[3] and a long history of industrial carbon pricing with an emissions trading credit system. Many companies have recently leased rights to assess underground formations to determine their CO_2 storage potential (shown as evaluation leases in the figure at right). Most operators are interested in using these formations to develop open storage hubs,[4] whereby existing emitters would access formations by extended CO_2 pipeline networks. These pipelines could provide link-ups for facilities that are far from storage (e.g., Pathways Alliance companies).[5]

In the future, **new or other existing facilities with CO_2 emissions** (e.g., production plants for ammonia, RNG, hydrogen, cement, steel, power) can similarly benefit from proximity to storage hubs, if these plants are outfitted with CCUS units.[6]

Existing and proposed CCUS infrastructure, GIS image*

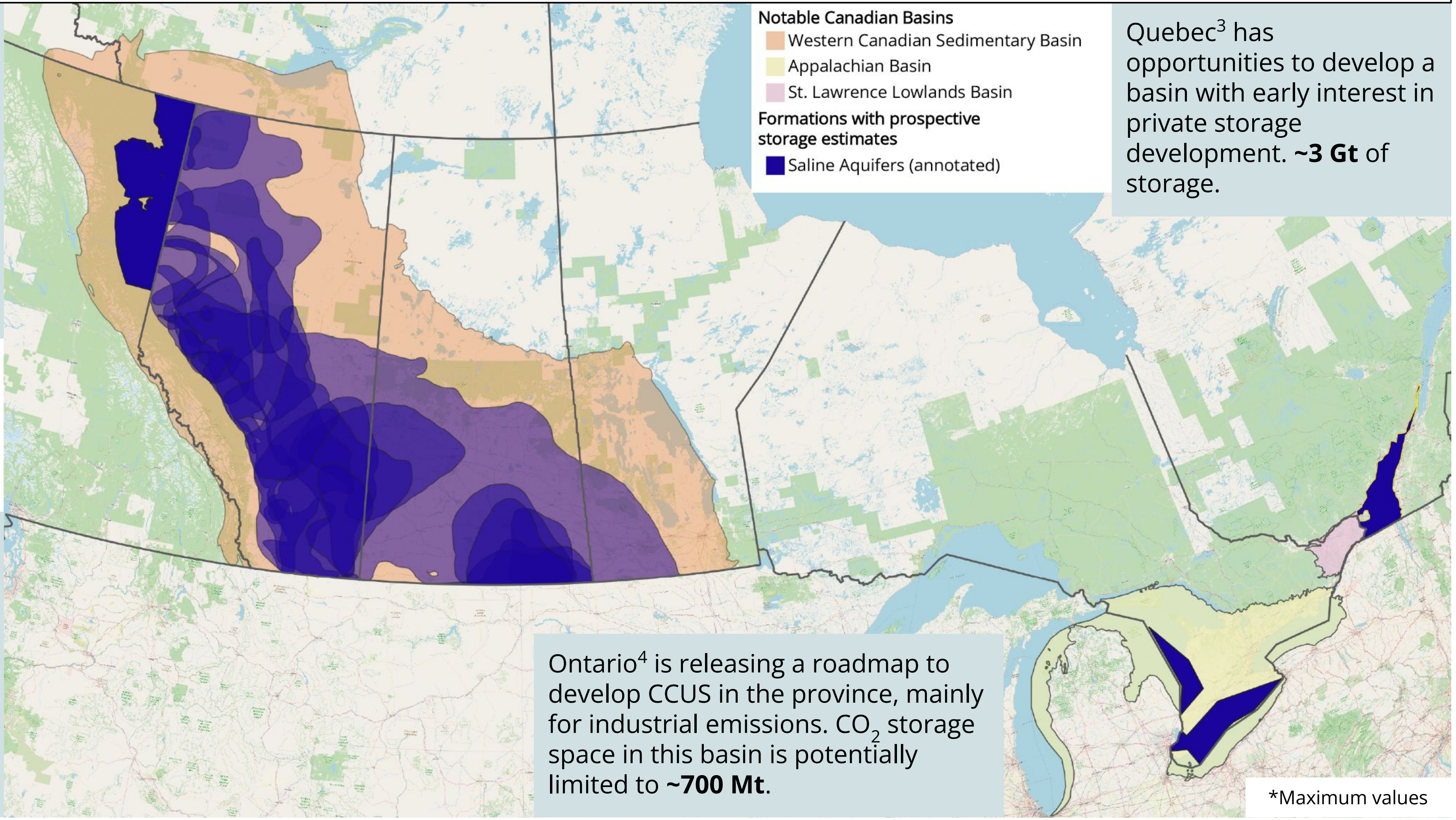


*Details and definitions in Appendix Slide 85

Potential reservoirs for onshore CO_2 storage in Canada[5]

This map shows potential reservoirs for CO_2 storage in Canada. There has been reservoir development activity in northeastern British Columbia (B.C.), Alberta, Saskatchewan, and Manitoba. Ontario and Quebec basins have not been developed for CCUS.

Alberta,[1,2] Saskatchewan[2] and Manitoba have access to well-studied storage reservoirs with up to **412 Gt*** of permanent storage in the Basal Cambrian. These reservoirs can store captured emissions from industries like power generation, chemicals, cement, oil sands, and blue hydrogen.



Quebec[3] has opportunities to develop a basin with early interest in private storage development. **~3 Gt** of storage.

Much of developed urban B.C. has limited opportunities for CO_2 storage, however the northwest has potential sinks (**3 Gt** of deep storage). B.C. is interested in sequestering emissions from oil operations and developing blue hydrogen (SMR+CCUS) in this region.

Ontario[4] is releasing a roadmap to develop CCUS in the province, mainly for industrial emissions. CO_2 storage space in this basin is potentially limited to **~700 Mt**.

*Maximum values

Pathways results for 2050

What role could CCUS play in 2050?

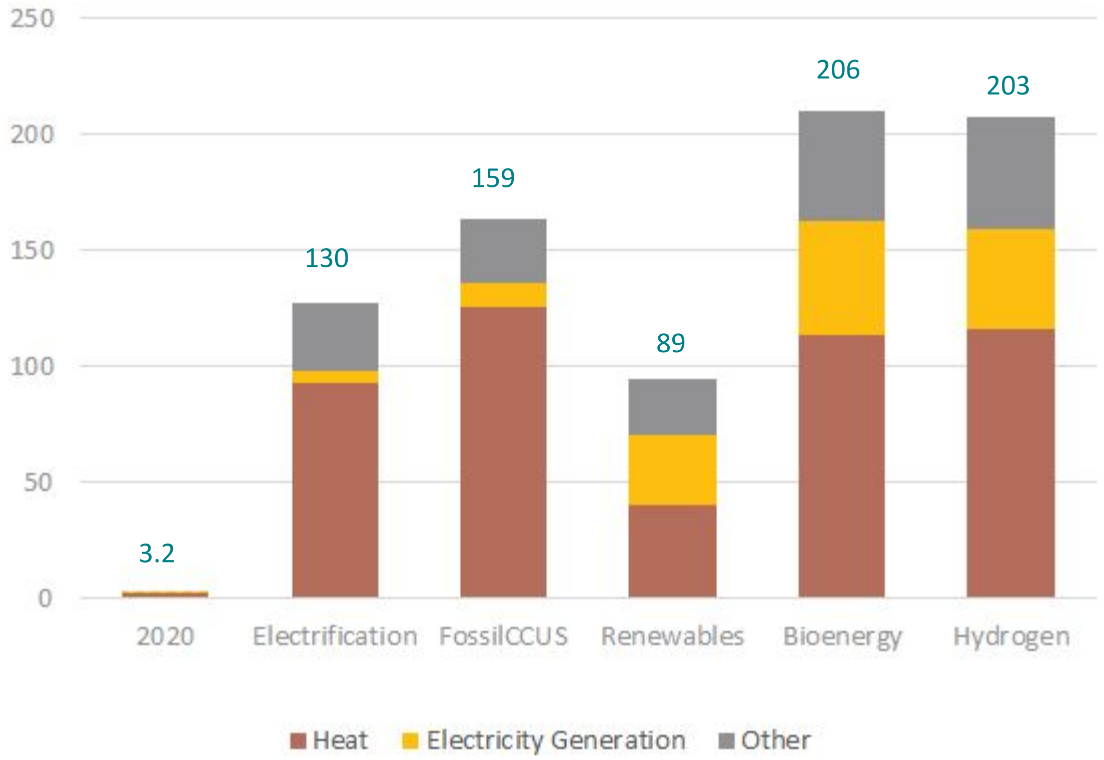
In our results, we see over 200 $MtCO_2$ captured through CCUS in 2050 in the Bioenergy and Hydrogen pathways. Here, CCUS tends to be deployed where other forms of emissions reduction (e.g., electrification) are challenging and/or expensive, and appears as:

- **Natural gas + CCUS** in industrial heat and electricity generation, usually replacing unabated natural gas combustion.
- **RNG + CCUS (BECCS resulting in net-negative emissions),** where RNG is blended with (or replaces) natural gas in heat and electricity generation.
- An abatement measure in other applications, including **cement and hydrogen production.**

Although our High Renewables pathway is set to phase out oil and gas production, it is notable that there remains persistent use of natural gas in select industries.[1] Some of these remaining natural gas emissions are captured, while RNG + CCUS also emerges as a net-negative emissions tool by 2050.[2]

In the model, all CO_2 is stored underground. The CO_2 is permanently stored (e.g., in deep aquifers) or injected into underground hydrocarbon-bearing formations to enhance oil recovery.[3]

CCUS by industrial end-use in 2050 ($MtCO_2$)[4]



In the figure above, *Electricity generation* refers to the combustion of RNG or fossil natural gas to produce electricity.[2] *Heat* represents the combustion of RNG or fossil natural gas to produce industrial heat. *Other* refers to CO_2 streams from cement and blue hydrogen production.

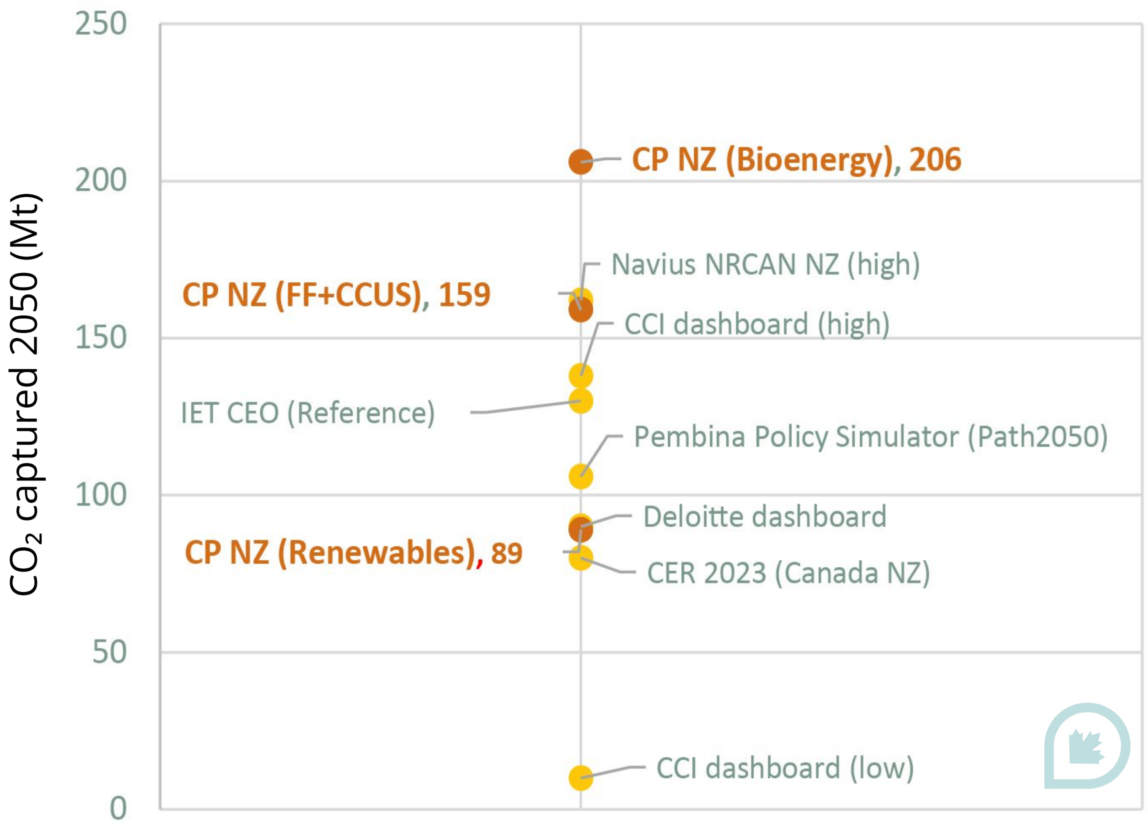
Comparison to other studies

CCUS deployment ranges widely between Canadian modelling studies and open dashboards. In studies referenced here, CCUS comprises from **~10 to 206 Mt of annual abatement by 2050,** usually as an addition to natural gas operations.[1] Part of the reason for the high variability is that different studies and/or pathways examined in the studies have varied amounts of natural gas remaining in the energy economy.

Our model results similarly present a wide range of CCUS outcomes, in that:

1. High RNG pathways (i.e., Bioenergy, Hydrogen) use RNG + CCUS to achieve negative emissions.[2] This is reflected in comparatively higher CCUS expectations.
2. Our Fossil with CCUS pathway is also on the higher end of estimates, due to high continued natural gas use in the economy which leads to more CCUS implementation.
3. Comparatively, CCUS is about 30% to 55% lower in the High Renewables pathway due to the oil and gas production phaseout. As noted previously, specific sectors continue to use fossil natural gas + CCUS[3] as an abatement tool, as well as RNG + CCUS as a negative emissions strategy.[4]

CCUS in net-zero and other estimates



Identifying CCUS opportunities

Downscaling current potential

Given that CCUS has a considerable role in our net-zero modelling results (and in other studies[1]), it is essential to reconcile model expectations with real-world opportunities and constraints. Current CCUS technologies are contingent upon access to appropriate geological storage. As it stands, CCUS opportunity exists only in those regions of Canada where deep **sedimentary basins are located.** As noted on Slide 54, these basins exist in **northwestern British Columbia, Alberta, Saskatchewan,** and parts of **southern Ontario and Quebec.**[2]

Based on this geological constraint, we investigate the possibility of near-term development of CCUS for existing high-emission facilities. We look at key sectors where CCUS can be readily implemented (e.g., chemical manufacturing, cement production, electricity generation, and oil sands) and assess these facilities' **geographic proximity** to infrastructure and geological storage. We then evaluate this **sector-based capture potential** as a function of distance to CCUS infrastructure and storage.

On the following slide, we plot these facilities by their degree of access to existing/proposed infrastructure and storage geology, defined as follows:

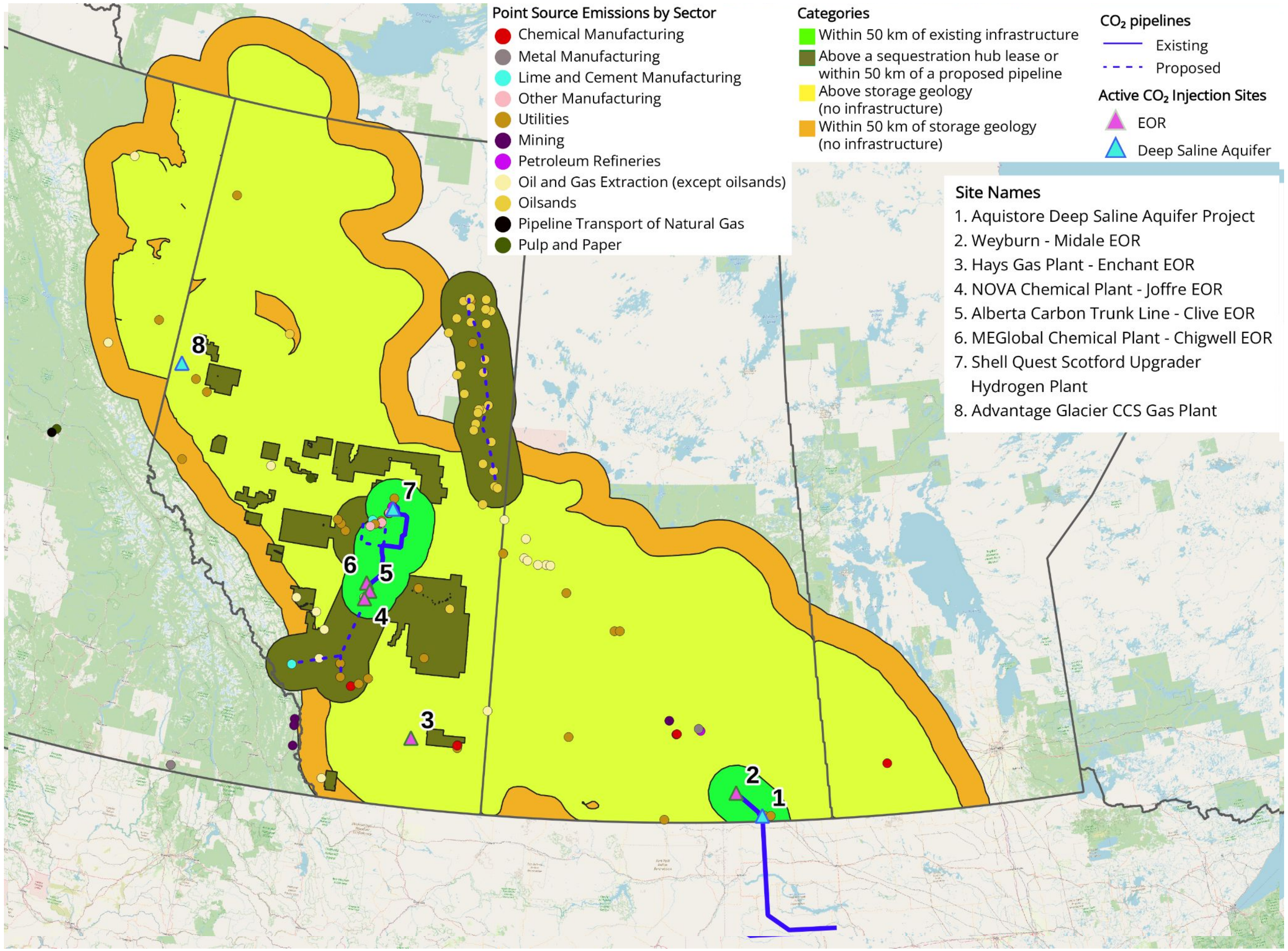
1. **Within 50 km of existing infrastructure:**[3] Facilities are located within 50 km of existing CO_2 trunk lines and injection sites connected to them.
2. **Within 50 km of proposed CO_2 pipelines or within land areas proposed for storage hubs:**[4] Storage infrastructure may become accessible to these locations in the near future, pending full build-out of proposed projects.
3. **Above storage geology (no infrastructure):** Facilities are directly above storage basins, but there is no existing or planned surface infrastructure within 50 km.
4. **Near storage geology (no infrastructure):** Facilities are within 50 km of a storage basin, but are not within 50 km of existing or proposed infrastructure.
5. **Far from infrastructure and storage geology:** An additional category, where facilities are more than 50 km away from storage and from infrastructure, is also examined.

Example of CCUS potential and high-emission facilities

This map illustrates central Canada's available onshore geological storage and available storage infrastructure (pipelines and injection sites).

An additional spatial layer has been added by **plotting high-emission facilities,**[1] which shows the position and type of these point sources. The proximity of these facilities to sequestration potential is denoted by the categories shown in the map. Here, we can see that (for example), the concentration of oil sands facilities near to proposed pipelines/hub leases in northeastern Alberta (dark green).[2]

This kind of sector-based spatial analysis can conceivably help inform where CCUS could be deployed to realize emissions reductions in regions with available storage.



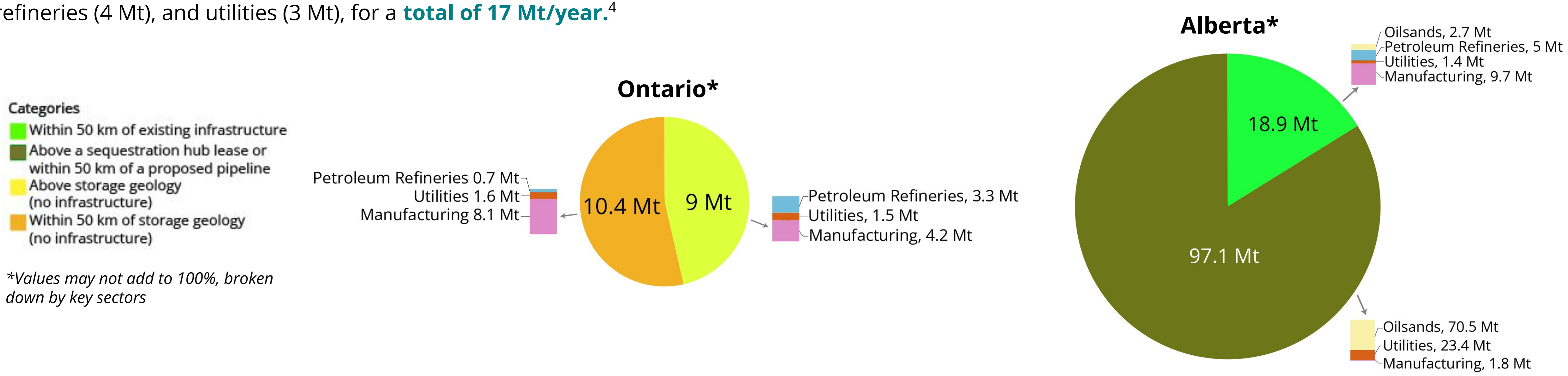
CCUS sector potential: Alberta and Ontario

In the visuals shown here, we further examine large point-source emitters[1] (as illustrated in the previous slide) against our criteria of access to infrastructure and storage geology[2] for Alberta and Ontario. These visuals, which are based on spatial data, illustrate the potential of CCUS implementation for different sectors **when accounting for regional level storage, CCUS infrastructure, and facility location.**

In Alberta, we find that several high-emission facilities are located above or within 50 km of existing or proposed storage infrastructure. This includes for oil sands (73 Mt), utilities (25 Mt), manufacturing sectors (12 Mt), and refineries (5 Mt) for a **total of 104 Mt/year**[3] that is theoretically possible to capture (at 90%). This contrasts with Ontario, where point sources are located above (yellow, 9 Mt) or near (orange, 10 Mt) storage geology, but do not have capture infrastructure in place or under development. This includes manufacturing plants (12 Mt), refineries (4 Mt), and utilities (3 Mt), for a **total of 17 Mt/year.**[4]

This suggests that deployment planning would benefit by considering the sectoral application of CCUS, in terms of which sectors can leverage CCUS based on their location. This sector make-up and potential uptake will necessarily differ by province.

This preliminary analysis also indicates that challenges for near-term CCUS deployment for existing emitters will differ by region. In Alberta, we see that a large proportion of existing emission sources lack linkages to existing/proposed infrastructure (dark green, 97.1 Mt); and in Ontario, the use of geological storage is not currently supported by infrastructure. For Ontario, we also suggest that planning for and investment into CCUS infrastructure will need to be evaluated against the total amount of emissions that can be stored over time, as prospective basin capacity is comparatively more limited in this jurisdiction.[5]



Values may not add to 100%, broken down by key sectors

Deployment gap considerations

What are key areas to consider next?

The next phase of our research will further develop our **spatial understanding of CCUS deployment,** which will be shared as a separate CCUS research brief in early 2024. This work will help further inform the considerations and sector opportunities associated with CCUS deployment in different provinces by using downscaling results.

For example:

- **Saskatchewan** has access to significant deep saline aquifers and a history of storage infrastructure development. Further exploration of CO_2 storage opportunity may be warranted for this area as the province has the largest sequestration potential in Canada, and moreover all large Saskatchewan emitters overlie potential storage geology (see yellow area on Slide 58).

- **Quebec and Ontario** may benefit from adopting robust regulatory frameworks to prioritize storage, as their major cement and metal manufacturing industries are located near potentially suitable basins. Nearly half of all Canadian metal and cement manufacturing emissions are located above potential storage in these provinces, which presents an opportunity for targeted capture.

We also note that the development outlook for CCUS may diverge from our model expectations when we further consider industry-specific emission and economic considerations.

For example:

- Flue streams from cement and chemical manufacturing, and process streams from blue hydrogen production, have much higher concentrations of CO_2 than utility and oil sands flue streams. These streams are thus more profitable and may signal a higher development priority for CCUS retrofits and new plants.[1]

- EOR, which is a main end-use of captured CO_2, is not a popular oil recovery strategy compared to other, cheaper forms of recovery,[2] and is also less supported by development incentives.[3]

- As verification and credit frameworks evolve and improve, other forms of CO_2 utilization and sequestration may take precedence.

Lastly we note that CO_2 utilization is not a significant consideration in our study, mainly because there is very little abatement from other uses of CO_2 (mainly urea production currently).[4] However, new technologies are emerging that could expand CO_2 utilization in the future, such as in the manufacture of polycarbonates[5] or to strengthen cement.[6]

Carbon capture and removal: direct air capture

Section 7

+ Overview
+ Pathway results for 2050
+ Comparison to other studies
+ Current state of play
+ Deployment gap considerations

Main points

Role of DAC in decarbonization pathways

Direct air capture (DAC) is an early-stage carbon dioxide removal (CDR) technology that appears in our model as a proxy for long-duration CDR, though we note this does not necessarily supplant future opportunities for other forms of CDR (such as new forms of DAC, mineralization and ocean-based methods).

DAC does not appear in our modelled pathways until 2040; however, all of our pathways require some level of DAC implementation by 2050.[1] DAC is commonly seen in our and other model results to offset persistent emissions in the economy that are technologically hard to abate (such as non-point source emissions that cannot make use of carbon capture utilization and storage (CCUS), e.g., heavy-duty vehicles or agriculture). Other net-zero model results tend to follow two trends: low DAC and moderate CCUS implementation, or high DAC with high CCUS implementation. Both trends are associated with the continued use of fossil fuels, but particularly so in the latter scenario.

Depending on the pathway, DAC removes between 13 and 259 megatonnes (Mt) of CO_2 in 2050 in our results. Overall DAC makes a modest contribution to net zero in the majority of our pathways, with the significant exception of the Fossil with CCUS pathway, which is reliant on continued high fossil fuel consumption across the economy. This pathway expects 259 Mt of DAC, with technology onset in 2040. This scale-up expectation for an as-yet early-stage technology[2] raises concerns about the energy demand, cost, and emissions risk associated with pathways that use DAC mainly as a means to abate continued emissions.

Our Electrification pathway also sees considerable DAC deployment as a negative emissions strategy (due to reduced economic attractiveness of bioenergy capture and storage or bioenergy with carbon capture and storage (BECCS) in this pathway, resulting from higher set biofuel prices).

Currently, our model represents DAC using a reference liquid DAC[3] plant and assumes that all removed carbon is stored in deep sedimentary onshore basins. As a result, the model only implements DAC where adequate storage basins exist,[4] including in British Columbia (B.C.), Alberta, and Saskatchewan. By far the greatest amount of DAC is anticipated in Alberta (e.g., our Fossil with CCUS pathway anticipates that 97% of all DAC will be deployed in Alberta by 2050). The DAC technology we model is complementary to a CCUS-favourable economy because the technologies share common storage infrastructure.[5] We note that there are many factors that would need to be carefully considered in high DAC-deployment scenarios, including but not limited to the substantial energy and water draw that would be associated with such developments.[6]

Overall, we consider that a key role for developing CDR technologies — including DAC — is in the removal of historical or legacy emissions.[8] Since the field is technologically young, many engineered solutions are in their infancy, yet could represent major opportunities to expand CDR technology and its impact. These include solid DAC[7] capture plants, ocean alkalinity modification,[9] and direct mineralization solutions, which may offer additional opportunities for Canada.

Overview

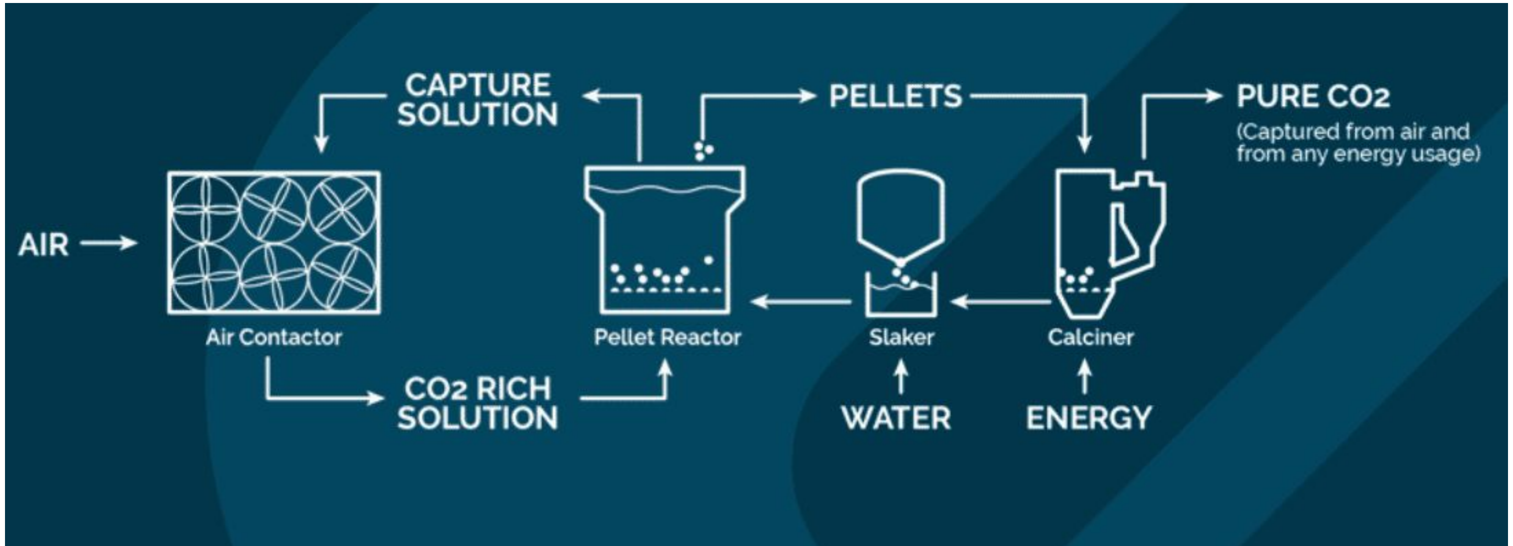
DAC is a carbon removal technology that filters CO_2 directly from the atmosphere, agnostically of the source. DAC technology differs from CCUS because it is not limited by a single emissions point-source, meaning DAC facilities can theoretically be located in a variety of geographies as long as an energy supply for operation is available. However, the DAC technology we examine in our results is geographically constrained by access to geological storage in the model. Also, DAC is not implemented in the economy until 2040 in our net-zero scenario results. This lead time reflects an anticipated cost reduction over time as the technology moves from current first-of-a-kind plants into lower-cost, scalable DAC implementation.[1]

Carbon dioxide removal (CDR), which includes DAC, is a broad field with many new and developing technologies, many of which are in the infancy of commercialization. While the model only includes liquid DAC (L-DAC), the development of new engineered and other systems may present opportunities to achieve CO_2 capture at higher scales (see the following slide).

In our model, CDR via DAC is employed primarily as an option to abate fossil fuel usage that is otherwise difficult or expensive to abate, but we note CDR is increasingly expected to have a major role to play in the removal of historical emissions.[2]

L-DAC process

Source: Carbon Engineering (CE)



CE's Direct Air Capture process, showing the major unit operations - air contactor, pellet reactor, slaker, and calciner - which collectively capture, purify, and compress atmospheric CO_2

In the **current state of play**, many CDR technologies are pre-commercial or in early pilot stage, and exhibit a wide range of costs per tonne of CO_2 removed. The technologies described below have the highest current opportunity to scale as costs come down over time,[1,2] though other aspects associated with actual deployment (such as plant capacity, ecosystem impacts, and resource usage, among others) will need to be carefully considered.

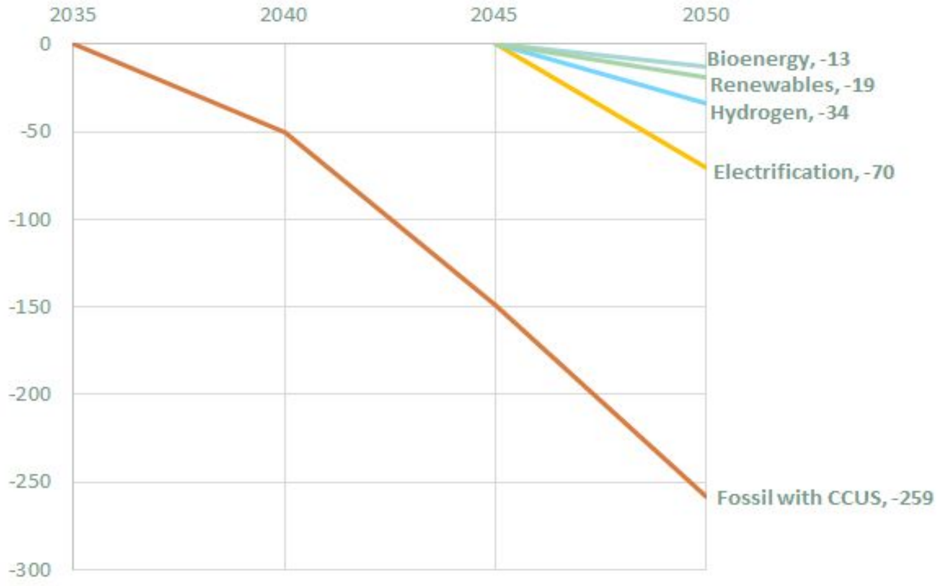
Engineered DAC		**Ocean alkalinity modification**	**Direct mineralization**		
Capture + underground storage (basin) (per gTech)[3]	**Capture**	**Capture + storage**	**Underground storage (basalt)**	**Storage**	**Capture + storage**
Liquid DAC	**Solid DAC**		**In-situ**	**Ex-situ**	**Enhanced weathering**
Commercial, modelled in gTech	Commercial, not modelled	Cost-competitive, not commercial, possibility to be modelled in gTech	Commercial, not modelled	Commercial, not modelled	Commercial, not modelled
Atmospheric gases are reacted in an alkali pellet reactor in order to precipitate CO_2 as a flue stream. Underground storage is modelled as formation storage in porous deep aquifers (or EOR, not in model).	Uses a specialized membrane that separates CO_2 from the atmosphere. This carbon is then stored underground, in aquifers or via *in-situ* mineralization.	Spreading fine-ground alkaline minerals into the ocean to neutralize ocean acidity and sequester CO_2 as bicarbonate ions, OR by artificially electrolysing ocean water into basic solutions.	Injecting CO_2 into mafic (basaltic rocks) where high pressure CO_2 reacts with alkaline rocks and directly mineralizes into carbonate minerals.	A reaction pathway where CO_2 reacts against alkaline rocks in order to mineralize the CO_2 into solid carbonate minerals, usually under high pressure conditions.	Crushing and spreading alkaline rocks over large areas (generally farmland) which subsequently react with atmospheric carbon and mineralize.
Current Status: • 1 syngas plant in B.C. (pilot). • 1 Mt/year DAC plant planned for B.C. • 1 Mt/year plant planned for development in Texas. **Benefits:** Low land usage (when paired with natural gas). High-capacity plants (1 Mt Carbon Engineering). **Drawbacks:** High energy usage.	**Current Status:** • Full scale capture-storage Orca plant in Iceland (Climeworks) capturing around 4 kt/year. • Several pilots in U.S. (e.g., Global Thermostat) **Benefits:** Low land usage. Does not necessarily require underground storage when mineralized. Cheaper to replace feedstocks relative to L-DAC. **Drawbacks:** Limited capacity plants. Currently, higher CAPEX than LDAC.	**Current Status:** Technology readiness level is high enough to model costs in gTech. **Benefits:** Reduces ocean acidification. Does not require CCUS. **Drawbacks:** Alters ocean chemistry with unknown ecosystem and other effects. Hard to measure impact.	**Current Status:** • Solid carbon pilot targeting offshore deep basalts, expected 0.6 Mt capacity. • CarbFix in Iceland storing S-DAC capture. **Benefits:** Permanent storage without need for monitoring. Does not compete with interests of oil reservoirs. **Drawbacks:** High expense for offshore.	**Current Status:** • Deep Sky is attempting to build a 1 Mt direct mineralization plant in Quebec using mine tailings. • CarbonCure cement plants. **Benefits:** Does not require underground storage. **Drawbacks:** Increase in mining activity. Hard to verify.	**Current Status:** Commercially deployed across the world, including Saskatchewan, unknown sequestration potential. **Benefits:** Increases farmland productivity. Does not require underground storage. **Drawbacks:** Unknown toxicity. High increase in mining activity. Hard to verify.

Pathways Results for 2050

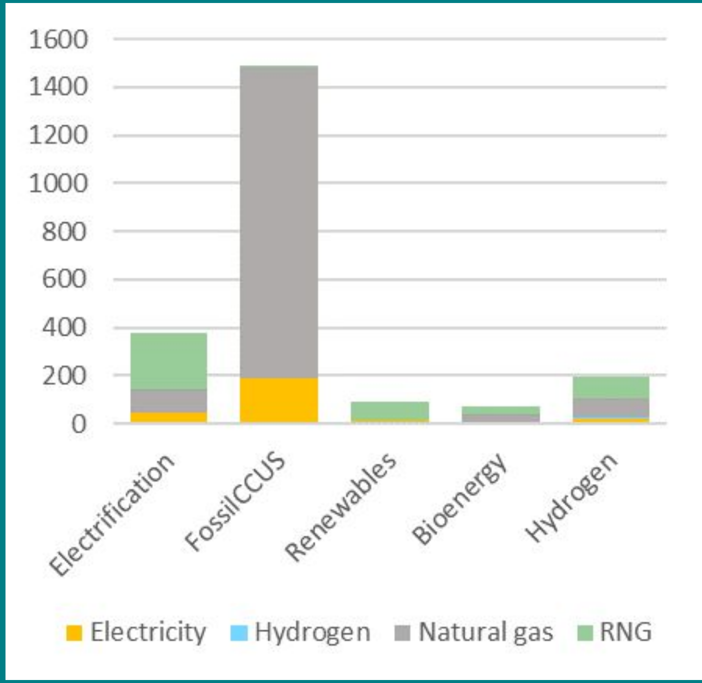
What are the expectations for DAC in 2050?

In our results, we see a relatively modest amount of DAC in three pathways as an abatement strategy to achieve net zero. A sizable 70 Mt of DAC are expected in the **Electrification** pathway in 2050 to offset the remaining emissions from fossil fuels, which continue to play a significant role in the energy economy.[1]

The **Fossil with CCUS** pathway stands out for the large amount of DAC it projects, with large-scale implementation beginning as early as 2040 and accelerating rapidly to nearly 260 Mt by 2050.[2] This is in addition to the 173 Mt of CCUS projected for the same pathway, meaning that over 430 Mt of emissions reductions in this pathway are achieved through carbon capture and engineered removal in 2050.



Energy consumption of DAC in 2050 (PJ)



The energy consumption profile of DAC in its current form[3] raises questions about viability, supporting infrastructure, and regionalized deployment:

- **High natural gas consumption** for DAC in the Fossil with CCUS pathway (1294 PJ by 2050) means emissions will continue to be generated through the additional use of fossil fuel.
- Significant **electricity consumption** (over 50 TWh in the Fossil with CCUS pathway by 2050) necessitates added electricity generation in regions favouring DAC deployment.
- Sizable **RNG consumption** across pathways for DAC operation may not be feasible given the feedstock supply constraints, and also may be better applied to reduce emissions in other sectors.

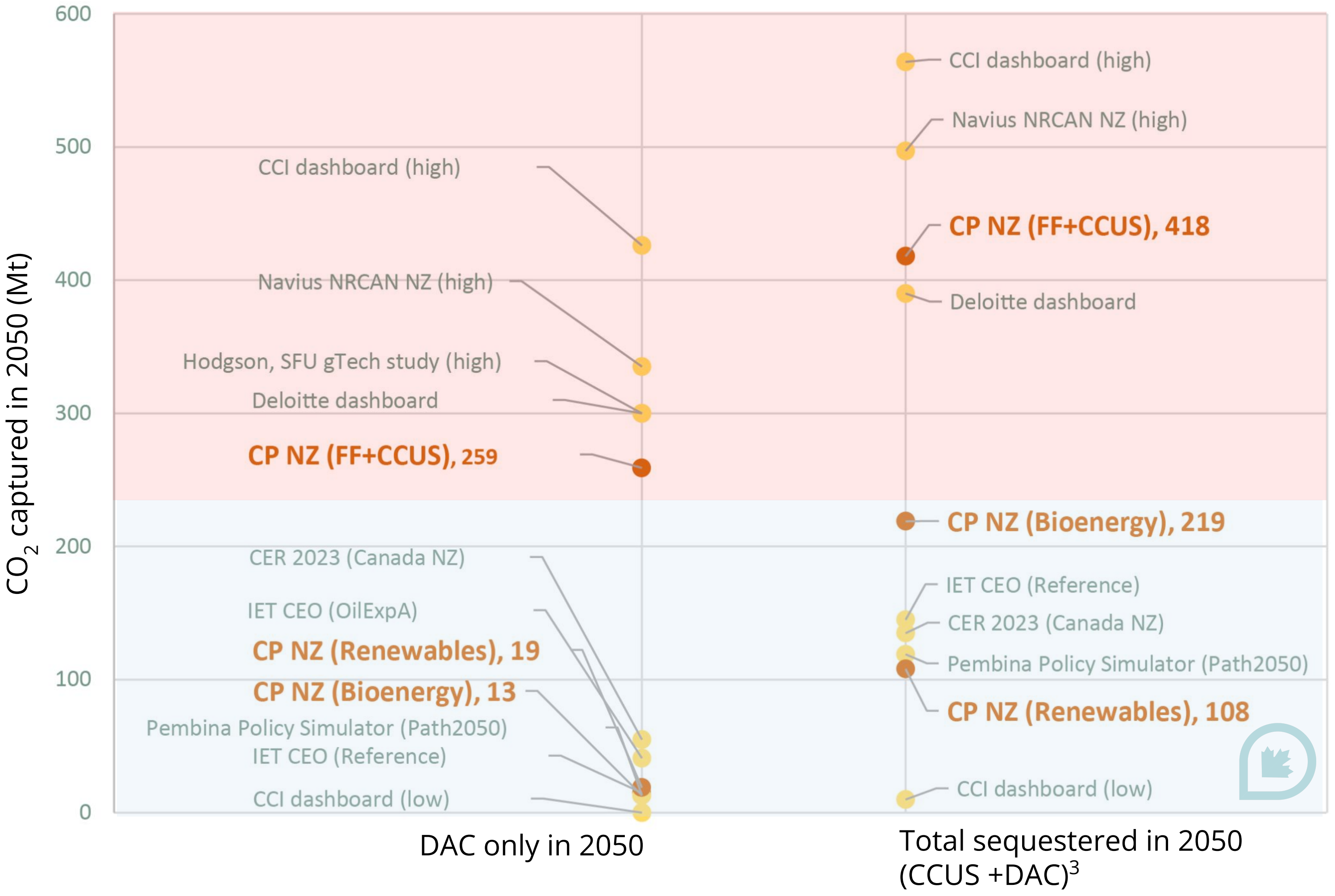
Comparison to other studies

Presented here are results from other studies that model the deployment of engineered DAC.[1] In these studies, we see two general groupings of results. In the lower set of results (*blue shaded area*), low amounts of DAC and moderate to high amounts of CCUS are observed (as in our Bioenergy and High Renewables pathways). These results either include a BECCS strategy (as a net-negative emissions tool, which increases overall CCUS deployment), or otherwise heavily leverage point-source CCUS.

In the upper results (*pink shaded area*)[2], high amounts of DAC and high amounts of CCUS are observed. In these results, BECCS is not prominent but CCUS deployment is still high. CCUS remains a significant abatement strategy in our Fossil with CCUS pathway, largely due to the low cost parameters assigned to CCUS.

Generally, high DAC deployment occurs when it is a cheaper abatement strategy vs. other available abatement options; however, the specifics of how, when, and why DAC is adopted will vary by study.

DAC in net-zero and other estimates



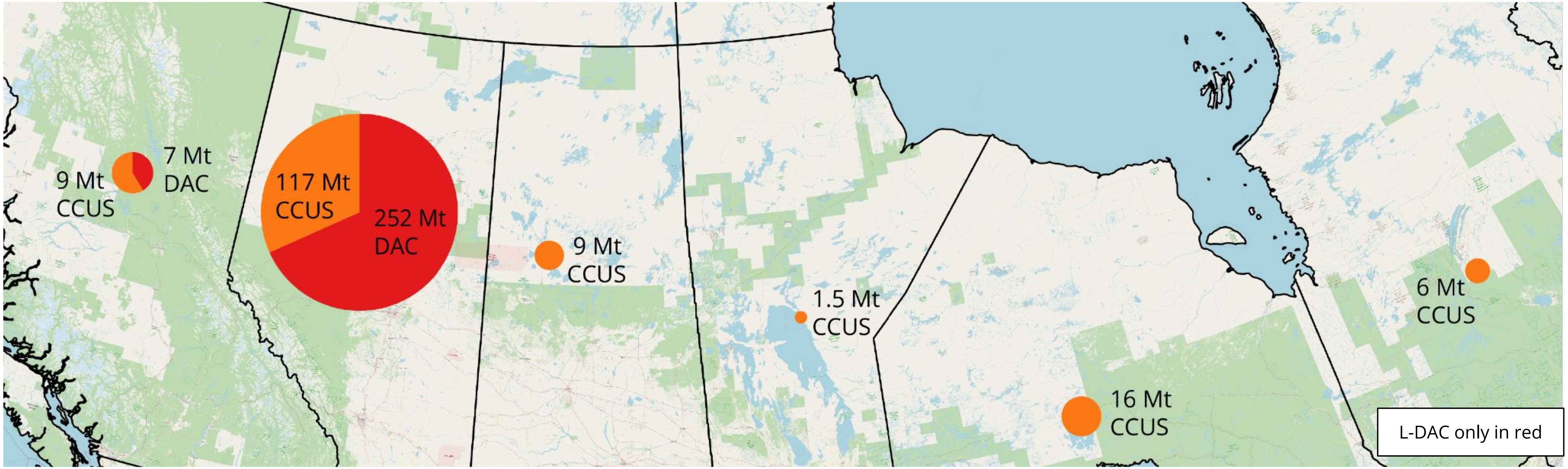
Modelled DAC projections for Canada

Model results project the largest DAC deployment in Alberta, followed by B.C. This is because the L-DAC plants, as modelled, are situated based on proximity to underground geological storage (see the figure below).[1] In this result, the siting of DAC in regions most actively developing CCUS is logical due to shared incentives,[2] similar carbon-pricing benefits, and to leverage CO_2 storage infrastructure and suitable sequestration reservoirs. Although DAC is connected to underground storage in the model, we note that captured CO_2 can also be used for EOR, and that other future uses for CO_2 may emerge.

The broader potential for CDR likely extends beyond the provinces shown in the figure as other storage opportunities are developed (such as in Saskatchewan), and as new DAC and other CDR technologies are developed and implemented. These latter include but are not limited to:

- Mine tailings across many provinces — including Quebec — which may be used for direct mineralization plants (e.g., Deep Sky pilot).
- Ocean alkalinity adjustment and offshore *in-situ* injection for coastal provinces.
- Provinces with high agricultural output may use enhanced weathering to increase yields and sequester carbon.

Total sequestration projected for the Fossil with CCUS pathway in 2050



Deployment gap considerations

What are key areas to consider next?

A benefit of DAC is that the facilities themselves require relatively little land, compared to other carbon removal options such as afforestation. This said, the high energy and water requirements[1] of the DAC system modelled will impact the placement of plants. **Land requirements for L-DAC vary by energy source**, where a natural gas-based system requires the least land area vs. a system powered by renewable energy, per the table at right.[2] Because L-DAC requires high temperature heat to operate, these systems currently require natural gas combustion, even if some parts of the system are electrified using other energy sources such as solar and wind. Notably, natural gas combustion (even when coupled with CCUS) produces some emissions that then have to be offset by DAC. Therefore, systems that incorporate more renewables have a higher overall CO_2 removal efficiency, though these are also geographically dependent on the availability of renewable resources.

There have been investigations into fully electrifying the heat requirement for DAC,[3] and the DAC Atlas[4] also considers siting near low-carbon heat sources (geothermal, biomass, solar, waste heat) to offset the natural gas heat requirement for L-DAC. Developments on both fronts would help to considerably improve the energy equation for L-DAC.

Our next avenue of exploration is to further examine **the energy, infrastructure, and land requirements associated with deploying DAC to the scales projected by our modelled pathway results**.

Related considerations include potential developments in reliable sources of revenue[5] for carbon-negative plants (e.g., via a well-developed carbon-credit market, and/or industrial carbon pricing), clear regulations around pore space,[6] and robust methods for measurement and verification.[7] This work will help further inform the feasibility and practicality of DAC as a lever for net zero, as well as the planning and policy support needed to implement and scale-up DAC technology.

L-DAC: system, energy source and land area

	DAC system and energy source	DAC plant area (km^2)	Energy source area (km^2)	Total area for a 1 $MtCO_2$/year plant (km^2)
Liquid DAC requiring high heat	natural gas with CCUS	0.4[b]	-	0.4
	natural gas with CCUS + solar PV	0.4	7.1	7.5
	natural gas with CCUS + wind	0.4	13.6	14.0
	natural gas with CCUS + geothermal[a]	0.4	1.5	1.9

[a] Geothermal energy is not currently represented in our model, but may warrant further exploration for applications including DAC
[b] Assumes co-location of natural gas infrastructure with DAC plant
Source: World Resources Institute [2]

Implications of high-DAC pathways

High expectations for DAC, especially in the Fossil with CCUS pathway, carry extensive implications.

First, a pathway with heavy reliance on fossil fuels only achieves net-zero in the model if there is **also significant use of carbon dioxide removal technology**, such as DAC. In this result, DAC depends on high consumption of natural gas, amounting to nearly 1300 PJ in the Fossil with CCUS pathway (see the figure at right on Slide 65), which is about a quarter of all natural gas use in the pathway in 2050.

Second, it will be **challenging to scale-up CDR to this level,** and particularly if Canada also elects to build out hundreds of megatonnes of CDR to offset its historical emissions.[1] Those megatonnes will require vast amounts of resources — energy, land, water— and investment, and so relying even more on CDR would be an extremely challenging direction to take.

Third, any large-scale use of CDR — whether for historical or residual emissions — will require **further innovation** to improve CDR technologies. At this point, we need to be cautious about projecting success based on late-stage carbon capture by technologies that are currently in early development stage. In the Fossil with CCUS pathway, DAC is only introduced in 2040 but increases rapidly to reach 260 Mt of removal in ten years. This would be a staggeringly fast scale-up rate, and would need to occur far faster than the adoption rates of any known commercial technology.

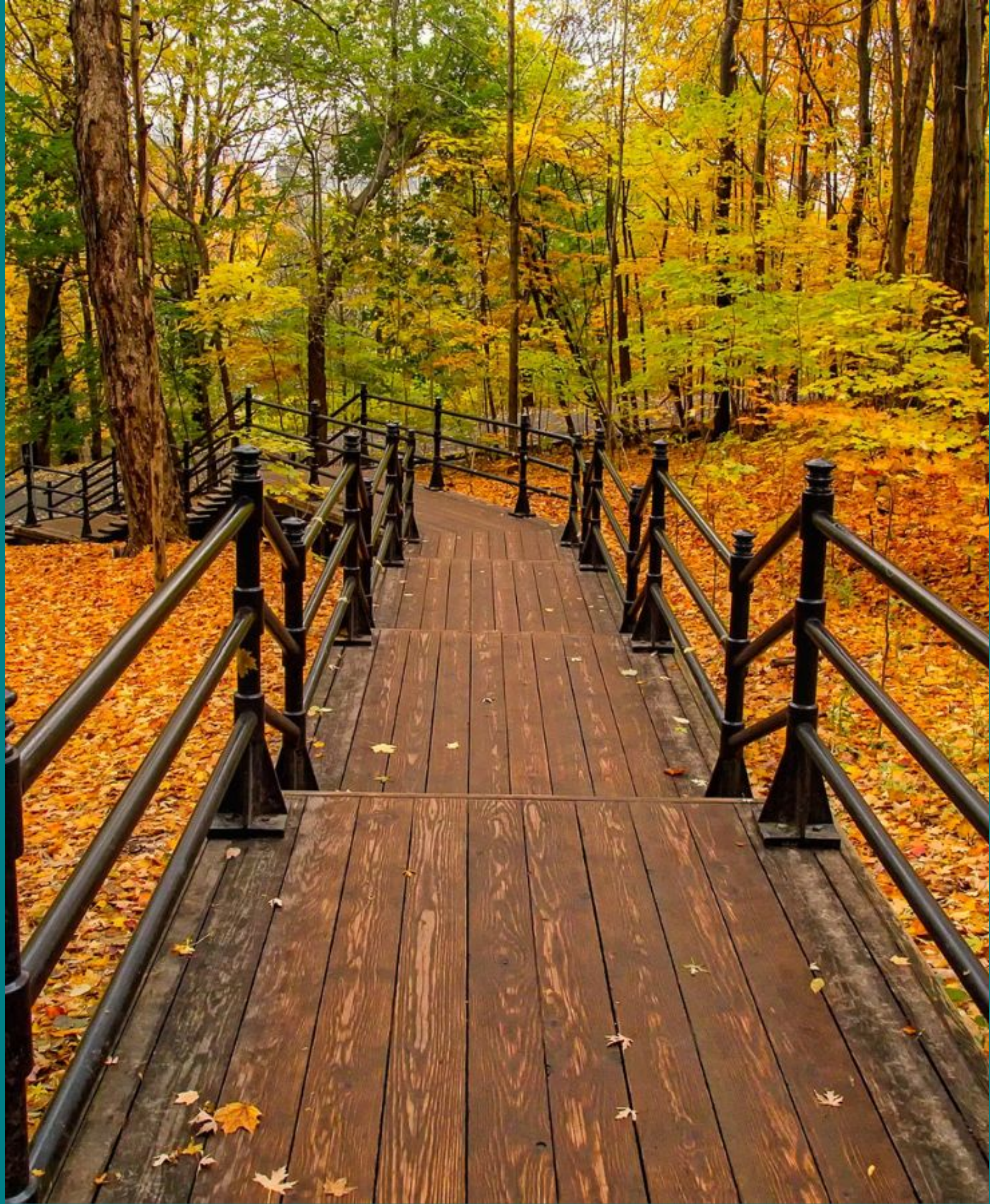
In addition to this context, the continued use of fossil fuels and associated co-dependence on DAC to meet net-zero goals carries major **economic and environmental risks**. These risks[2] are not addressed within the model (and are therefore not explicitly reflected in the modelled economy), but include that:

1. **The model lacks foresight**, meaning that decisions leading to "carbon lock-in" may actually not be economically optimal in the long-run, especially if given a clear net-zero policy signal.[3]
2. The direction of continued fossil fuel use, which would only be enabled through DAC in our model, **could come under strain given that** global energy agencies, such as the IEA, are estimating that world fossil fuel demand will peak in 2030.[4] Investing in additional fossil-fuel infrastructure must be weighed against the **risk of stranded assets**, which can have significant ripple effects on local economies and jobs.[5]
3. Most importantly, missed DAC/CDR targets and timelines within a DAC-reliant pathway can mean **missed emission targets**, higher cumulative emissions, and Canada failing to achieve net zero.

For these reasons, until CDR technologies are more established, DAC (and CDR) should be primarily considered as a tool to address historical emissions.

Next steps

Section 8



Next steps

Our modelling analysis illustrates the varied potential, and tradeoffs, inherent in the key technologies to help Canada reach net-zero, including: (1) increased electrification combined with renewables expansion, (2) the use of renewable natural gas (RNG), (3) the application of carbon capture utilization and storage (CCUS), and (4) the selective use of direct air capture (DAC) depending on the energy pathway prioritized. We also note that use of negative-emission technologies (whether it is DAC or bioenergy with carbon capture and storage [BECCS], as implicit in our RNG results) are required by the model for reaching our net zero target. These general categories capture the **main shifts in the energy economy that lead to decarbonization in our results**, and are a consequence of the technological and cost parameters applied in the model.

Our results to date **largely align with those in other net-zero reports** that use similar types of models. However, our subsequent research shows that a **sizable delta** exists between present-day resource potential and associated planning, compared to the modelled projections for 2050. This delta has not been explored in detail in the net-zero research we reviewed for this paper.[1] Given the time required for realizing large-scale infrastructure change in Canada, this **deployment gap** is critical to address in order to achieve net zero, and needs to inform the activities of government policymakers, system planners, researchers, and climate change-focused organizations, among many other entities.

Consequently, our next research product will provide an in-depth examination of how and where Canada can best take advantage of these — and other — net-zero opportunities. This includes further exploring how to apply these opportunities in **high-emitting sectors,** the **provincial contexts and potential** for regional deployment, and the overall changing role of fossil fuels throughout the economy.

In a series of upcoming research briefs, we will also map the land-use considerations associated with deploying our net-zero projections. These briefs will account for **geographic challenges and opportunities**, identify regional **co-benefits** of deployment, and provide a more complete understanding of the **infrastructure requirements** for achieving a net-zero transition.

Our work will culminate with **policy recommendations to help close the 30-50 gap**. This is the 400 megatonnes (Mt)/year gap between the emissions reductions that will be delivered in 2050 by existing Canadian climate policy (which is primarily focused on achieving our 2030 targets), and our 2050 net-zero target of 50 Mt/year.

For more information, contact: research@cleanprosperity.ca

Appendix A: Methodology and parameters

Section 9

Model limitations

In addition to general limitations pertaining to large general-equilibrium models and modelling broadly speaking, we highlight here a number of limitations that pertain to the interpretation of our results (select limitations are also discussed throughout the deck when relevant). A key issue is that, like most models, our model builds on current/emerging technologies and socio-economic structures and is therefore limited in its ability to simulate deeper systemic change.[1]

For all results, the model assumes that the necessary **infrastructure is available for purchase/building**[2] (e.g., to charge electric vehicles) and that **supporting materials and supply chains**, such as microchips, lithium, and nickel, are readily available and accessible. In reality there are ongoing shortages of critical materials that can impact the large-scale production of EVs, as well as wind turbines, solar panels, and many other electrification technologies.[3]

With regard to our **electricity results**: there are differences in how the electricity sector is modelled in gTech and Integrated Electricity Supply and Demand (IESD). Furthermore, many barriers to electrification are **regulatory and institutional** in nature.[4]

These barriers are not well reflected in the model, but are subject to further exploration in future research products.

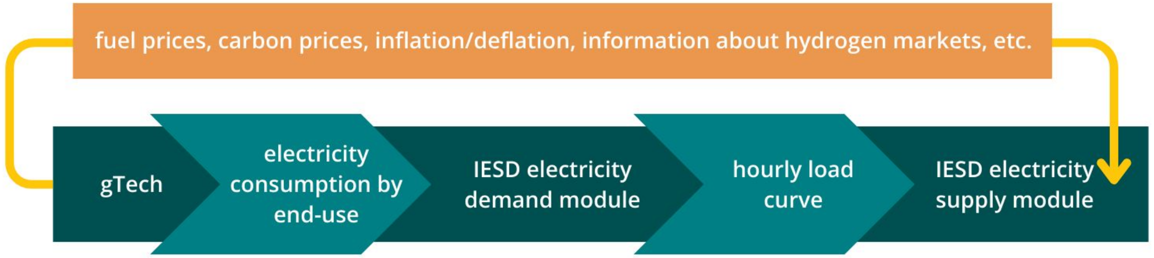
With regard to **bioenergy**: the model does not represent all aspects of a bioeconomy. The model does represent key dynamics of production and consumption of substitutable/blendable fuels such as biodiesel, ethanol, and RNG. However, it is limited in its ability to simulate the emergence of a more complex bioeconomy that incorporates the competition dynamics of feedstocks for emerging bioproducts (from economic and emissions perspectives), takes full advantage of waste resources, and outlines more strategic uses for high-cost biofuels like RNG. The limited holistic representation and system-building in the models is also a limitation for simulating a complex **hydrogen** economy.

The model is limited in accounting for **environmental factors and changes**, including variation in **wind and solar resource** (their availability is based on 2015 base year), possible changes to **water** and **bioenergy feedstock** supply, and non-energy-economy greenhouse gas (GHG) emissions such as **forest fires**, which are becoming an increasingly important issue in Canada.[5]

Model architecture

Model detail specific to pillar simulation

Our modelling approach combines two models: **gTech and Integrated Electricity Supply and Demand (IESD).**[1] The gTech model is a technologically-detailed general-equilibrium model that simulates the energy economy by combining technological choice, macroeconomics, and energy supply within an integrated framework.



Electricity

The **electricity sector** is modelled using Navius' gTech model in conjunction with IESD (see the figure at right).[2] The electricity demand from gTech is passed to the IESD model, which simulates how the electricity sector makes capacity and dispatch decisions based on an hourly load curve, as well as energy prices and costs of installing and operating different power sources including energy storage. The results, which are presented in five-year time steps, are useful in providing a large-scale picture of the behaviour of electricity consumption and generation within a changing energy economy.[3]

Renewable natural gas (RNG)

The model includes first- and second-generation RNG production pathways and assumes that the required feedstock is available when needed, up to a set limit based on current feedstock potential estimates in secondary research.

Our cost assumptions for RNG are detailed in **Appendix Slide 77 ,** and are lower than in some other reports, which partially explains the relative "bullishness" of the model with respect to RNG. These costs represent the 2020 starting costs at the factory level,[4] and do not account for a variety of factors (per **Appendix Slide 77**).[5]

Hydrogen

Four main production pathways for hydrogen are included in the model developed for Clean Prosperity: steam methane reforming (SMR), electrolysis, natural gas pyrolysis, and biomass gasification. Production costs are detailed on **Appendix Slide 78**. Hydrogen is modelled as an energy carrier (i.e., fuel), as well as a feedstock.

Carbon capture, utilization and storage (CCUS)

The model includes several types of CCUS technologies that capture CO_2 at a point source, which are parameterized on a cost curve from first-of-a-kind (current) to nth-of-a-kind (future minimum), detailed in **Appendix Slide 79**.

Direct air capture (DAC)

DAC is assumed to be deployable at any location (not tied to a point source) so long as access to geological storage is available,[6] parameterized based on the most current DAC research. See **Appendix Slide 80**.

Model configuration – limitations in the electricity sector

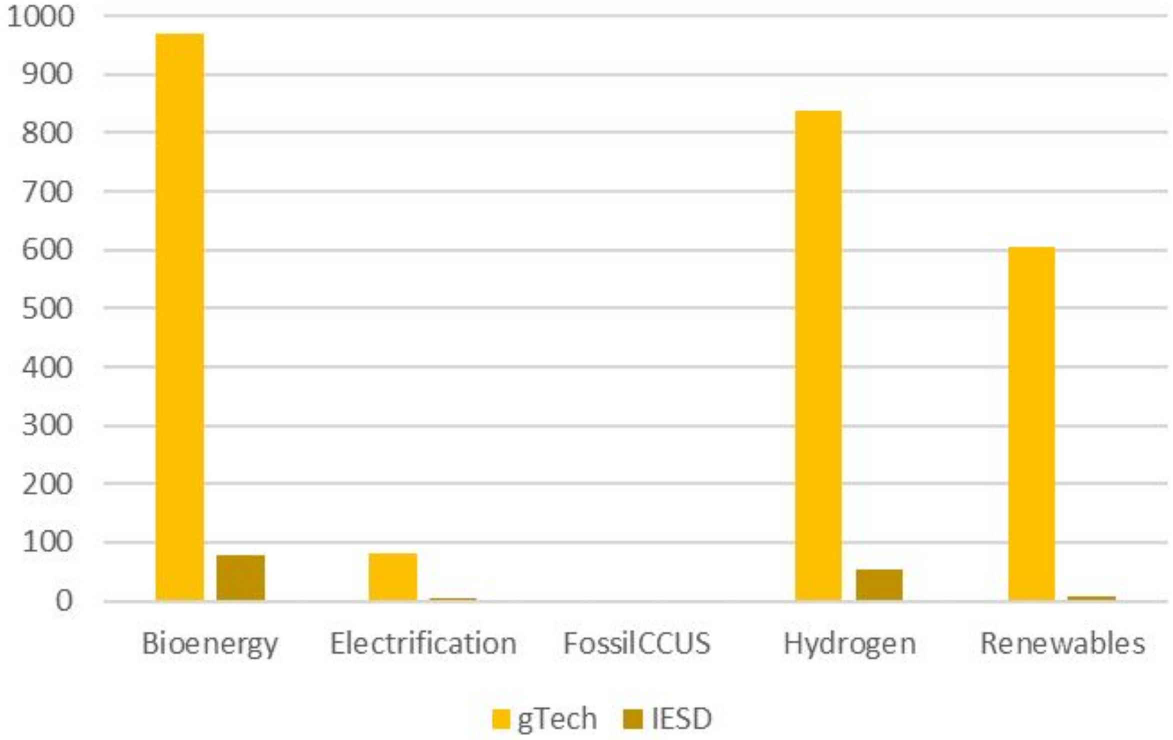
RNG in electricity generation (gTech and IESD)

Given the partial integration of IESD with gTech in our version of the model,[1] there is a bifurcation in the way electricity generation is projected to occur in the future depending on which model is employed. RNG consumption in the electricity sector is among the major differences (see the figure at right) that appears in three out of our five net-zero pathways. For this sector, gTech assumes comparatively more RNG (and more bioenergy with carbon capture and storage [BECCS] through RNG+CCUS) in the electricity sector compared to IESD.[2]

Two dynamics are of importance to highlight:

1. **IESD is able to better represent the deployment potential of different types of electricity generation,** as it encompasses a larger set of electricity-specific functions and parameters at a more granular temporal resolution than gTech. This results in IESD **favouring the buildout of wind and solar capacity** more strongly than gTech, with consequently less need for combustion-based generation and RNG in the electricity sector.
2. **gTech is the main model used in our analysis as it accounts for the economy at large** and considers the cost of CO_2 abatement for compliance with net zero in every sector. This "big picture" is not captured by IESD.

RNG consumption by the electricity sector in 2050 (PJ) — gTech and IESD comparison



Due to its superior functionality in electricity modeling, we employ IESD for our electricity sector analysis. However, the broader energy economy is represented by gTech, meaning that the inter-model differences within the electricity sector can imply discrepancies in other sectors, which are not reflected in the gTech output.[3] Therefore, in our analysis we are mindful that reduced BECCS in the electricity sector (as implied in IESD output) could mean that further emissions reductions may be required in other sectors in some pathways, beyond what is currently shown in our gTech output. It remains important to note that despite some differences, **both models project a large role for renewables in the energy system, as well as the potential for RNG**.

Electricity: wind, solar, and small modular nuclear cost parameters

Technology	CP cost assumptions (2020 $CAD/kW)			Notes	Sources
	Reference	**Low**	**High**		
Solar	Capital cost $3,257 in 2015 declining to $808 by 2030 and $608 by 2050. Fixed operating cost of $30.	Capital cost $3,257 in 2015 declining to $665 by 2030 and $458 by 2050. Fixed operating cost of $30.	Capital cost $3,257 in 2015 declining to $1,183 by 2030 and $740 by 2050. Fixed operating cost of $30.	Our costs fall within low range of NREL estimates for utility-scale solar; within the high range of CER assumptions; within high range of EPRI assumptions; within high range of ECCC assumptions. Some studies also differentiate between distributed and undistributed solar.	NREL 2023[1]; CER 2023[2]; EPRI 2023[3]; ECCC 2022[4]
Onshore wind	Capital cost $2,250 in 2015 declining to $1,048 by 2030 and $778 by 2050. Fixed operating cost of $51.	Capital cost $2,250 in 2015 declining to $734 by 2030 and $515 by 2050. Fixed operating cost of $51.	Capital cost $2,250 in 2015 declining to $1,138 by 2030 and $951 by 2050. Fixed operating cost of $51.	Our costs fall within high range of NREL estimates; within low range of CER assumptions; medium range of EPRI assumptions; within high range of ECCC assumptions.	NREL 2023; CER 2023; EPRI 2023; ECCC 2022
Offshore wind	Capital cost $6,347 in 2015 declining to $2,999 by 2030 and $2,255 by 2050. Fixed operating cost of $150.	Capital cost $6,347 in 2015 declining to $2,100 by 2030 and $1,472 by 2050. Fixed operating cost of $150.	Capital cost $6,347 in 2015 declining to $3,255 by 2030 and $2,720 by 2050. Fixed operating cost of $150.	Our costs fall within high range of NREL estimates; within high range of ECCC assumptions.	NREL 2023; CER 2023; ECCC 2022
Small modular nuclear reactors	Capital cost $10,167, levelized cost of **electricity** $136/MWh. Capital cost $5,219, levelized cost of process **heat**[5] $70/MWh. Low cost sensitivity:[6] Capital cost of $5,924 in 2020 CAD. Using a 9% discount rate, the low capital cost value results in a LCOE of $98/MWh.			Our capital cost assumptions are considerably higher than those in CER (projected to fall to $6,519/kW by 2050) and EPRI (projected to fall to $5000-5500/kW by 2050); higher than NRCan median estimate of $13,565/kW, however, our low cost sensitivity values are on the lowest range of the ERPI estimates.	CER 2023 EPRI 2021; NRCan 2023[7]

Renewable natural gas: cost parameters and comparison with other sources

RNG production pathway	Production cost ($/GJ[1])					
	2030 max in Fortis 2022	2050 max in Fortis 2022	Range from Torchlight 2020	In Quebec from Deloitte 2018	Navius NRCAN 2023	CP Modelling*
Agricultural waste to RNG	24	24	19–57, depending on technology, feedstock, and scale of facility	60–65	19.3	19.3
Source-separated organic (green bin) and industrial food waste to RNG	24.5	24.5		15–50		
Water treatment sludge to RNG	30	30				
Landfill gas capture and conditioning to RNG	24	24			14.2	14.2
Wood gasification in lime kilns of kraft pump mills to syngas methanation to RNG	27	20		15–27	26.2	26.2
Wood pyrocatalytic hydrogenation in pressurized chamber with SMR-derived hydrogen to RNG						

* These costs represent the 2020 basic starting point and will change in modelled future years depending on the demand for RNG in those years. Costs reflect the input costs at factory level and do not include costs of transportation or possible regional and seasonal variations in costs. Transportation costs can be quite high for many feedstocks due to high moisture content and low bulk density.[2] Costs reflect possible competition dynamics with other demand sectors for feedstocks. However, it is also assumed that no crops are grown exclusively for energy (i.e., only residues from food crops are used). We note that second-generation RNG production technologies are assumed in the Navius model to be readily available at the required scale, but are currently not at commercial stage.

Hydrogen: production cost parameters and comparison with other sources

Hydrogen Input Costs ($/kg)	Steam Methane Reforming/Autothermal Reforming	Electrolysis	Natural Gas Pyrolysis	Biomass Gasification
CURRENT				
CP modelling ($CAD2020/kgH$_2$)	Low: 1.74 (Hydrogen pathway) Ref: 2.10 High: 3.40	Low: 3.86 (Hydrogen pathway) Ref: 4.44 High :4.84	Low: 2.22 (Hydrogen pathway) Ref: 2.47 High: 2.72	Low: 2.18 (Hydrogen pathway) Ref: 2.51 High: 2.66
Transition Accelerator[1] (CAD/kgH_2$)	~1.2–3.4	~3–7.5		
Canada Energy Regulator (Evolving Policy 2021)($USD2020/kgH$_2$)[2]	Natural gas: 1.6–2	On-grid: 6–8 Dedicated: 8–10		
National Energy Technology Laboratory[3] (USD/kgH_2$)	Natural gas/coal: 1.06/1.54 1.54 (ATR)	Electrolysis: 4.15–10.30 All green: 1.42–10.30		BMG: 1.77–2.05 Other biomass pathways: 0.54–2.83
International Energy Agency[4] (USD/kgH_2$)	Natural gas/coal: ~1.75–3	Solar, wind: ~4–9 Nuclear: ~3.5–7		
Government of Alberta Report[5] (CAD/kgH_2$)	Natural gas: 1.75 (SMR ,ATR)	Renewables on and off grid : ~8		BMG: 1.77–2.05 Other biomass pathways: 0.54–2.83
Government of B.C. Report[6] (CAD/kgH_2$)	~ 2.25	On-grid: 5 Dedicated 7.5	Thermal: ~1.75 Plasma: 2.25	~3
Institut de l'énergie Trottier CEO2021[7]	Reports in $/kW	Reports in $/kW		Reports in $/kW
FUTURE				
CP modelling ($CAD2020/kgH$_2$)	Declines endogenously	Declines endogenously	Declines endogenously	Declines endogenously
Transition Accelerator "max future"[1] (CAD/kgH_2$)	~1–2.9	~2.5–5		
Canada Energy Regulator[2] ($USD2020/kgH$_2$)	1.5–1.7	Ongrid: 4–6 Dedicated: 1.5–2		
International Energy Agency[3] (USD/kgH_2$)	Natural gas: ~1–2 Coal: ~1–2.25	Solar, wind: ~1.75–4 Nuclear: ~2.5–5		

Carbon capture, utilization and storage: cost parameters[1]

CCUS application	Cost range ($CAD2020/t$CO_2$ captured)	
	First of a kind (current)	n^{th} of a kind (future minimum)
Coal power generation retrofit[2]	164–188	77–113
Natural gas combined cycle	116–133	54–80
Co-generation (natural gas)	147–246	88–146
Cement heat (coal)	103–173	60–99
Cement heat (natural gas)	128–262	62–127
Industrial heat (coal)	97–162	51–86
Industrial heat (natural gas)	128–262	73–150
Low-temperature industrial heat (coal)	97–162	51–86
Low-temperature industrial heat (natural gas)	128–262	73–150
Steam methane reforming hydrogen production	66–135	63–130
Formation CO_2[3]	37–62	20–34

Direct air capture: cost parameters and comparison with other sources

DAC input costs	Liquid DAC	Solid DAC	Ocean Alkalinity	In-situ	Ex-situ	Direct mineralization
CP modelling — gTech first-of-a-kind[1] (CAD/tCO_2)	Low: 261 Ref: 354 High: 501		Low: 150 Ref: 247 High: 500			
CP modelling — gTech n^{th}-of-a-kind (CAD/tCO_2)	Low: 115 Ref: 162 High: 202					
Industry estimates: (USD/tCO_2)	Carbon Engineering:[2] 94–232	Climeworks:[3] 500–600				
Ozkan et al. 2022, assuming natural gas-fueled DAC[4] (USD/tCO_2)	208–463	101–1433 mid. ~ 233				
Global DAC TIMES model:[5] (USD/tCO_2)	100–300	50–350				
Pembina 2023[6]: (USD/tCO_2)	130–390 [2]		52–338 [7]	Onshore: [8] 26–39 Offshore: 260–520	68–300 [9]	65–260 [7]
International Energy Agency[10] (USD/tCO_2)	125–335					

Appendix B: Additional tables

Section 10

Sources

Graph notation [1]	Reference | notes
CP NZ (*Pathway*)	Felder, M. and A. Hervas (2023). "Achieving net-zero pathways for Canada: What progress are we on track to make by 2050? Interim Paper I", Clean Prosperity. NZ(*Pathway*) scenarios refer to the five net-zero pathways explored as part of Clean Prosperity's net-zero modeling project.
CCI BCS (*high/low*)	Canadian Climate Institute (2022). "Bigger, Cleaner, Smarter. Pathways for aligning Canadian electricity systems with net zero", report
CCI dashboard (*high/low*)	Canadian Climate Institute (2021). "Canada's net zero futures 2021: data and figures". 440 Metagonnes
CER 2021 (*Evolving Policy*)	Canada Energy Regulator (2021). "Canada's energy future 2021". report
CER 2023 (*Canada NZ/Global NZ/Current*)	Canada Energy Regulator (2023). "Canada's energy future 2023". report
Deloitte dashboard	Deloitte (2021). "How Canada can decarbonize by 2050". report
DSF 2022 (*BAU/Zero/Zero Plus*)	David Suzuki Foundation (2022). "Shifting power: zero-emissions electricity across Canada by 2035". report
ECCC 2022 (*high/low*)	Environment and Climate Change Canada (2022). "Exploring approaches for Canada's transition to net-zero emissions". report
EPRI 2021 (*Baseline/NZ*)	Electric Power Research Institute (2021). "Canadian national electrification assessment: electrification opportunities for Canada's energy future". report
Hodgson, SFU gTech study	Hodgson, D. (2022). "The economics of air capture of CO_2 in Canada", Simon Fraser University Thesis. report
IET CEO (Reference/NZ50)	Institut de l'énergie Trottier (2021). "Canadian energy outlook 2021". report
Navius NRCAN NZ (*high/low*) or Legislated (*high/low*)	Navius and Natural Resources Canada (2023). "Canada Energy Dashboard". data
Pathways dashboard (*high/low/BAU/NZ50*)	Pathways explorer (2023). A project led and designed by Institut de l'énergie Trottier, modelling by ESMIA, interfaces by Kashika Studio. data
Pembina policy simulator (*high/low/BAU/Path2050*)	Pembina Institute (2023). "Canada's energy policy simulator". data
Public policy forum 2023	Public policy forum (2023). "Project of the century. A blueprint for growing Canada's clean electricity supply - and fast". report
Transition Accelerator	Towards Net-Zero Energy Systems In Canada: A Key Role For Hydrogen (2020). report

Potential for renewable natural gas production in Canada

Province	RNG Potential (PJ/year)							
	Torchlight 2020[1]	Torchlight 2020	Hallbar Consulting 2017[2]	Pembina 2020[3]	Deloitte and WSP 2018[4]	Norouzi et.al. 2022[5]	Fortis 2022[6]	Canadian Biogas Association [7]
	Including herbaceous	Excluding herbaceous	Long-term achievable	Organic waste within BC	Includes forest biomass	All organic waste streams	Forest biomass technical potential 2050	
British Columbia	20	16	11.9	10		401	273	
Alberta	105	15				179		
Saskatchewan	112	3				145		
Manitoba	70	4				73		
Ontario	224	41				280		
Quebec	116	38			188.5	298		
New Brunswick	5	4				12		
Nova Scotia	4	2						
PEI	2	0						
Newfoundland and Labrador	1	1						
Canada	**660**	**123**				**1388**		**1300**

Hydrogen transport calculation, Navius Research

Units	Value	Description	Source
PJ	177–505	Total Shipping Load	Provided by client
Weight (kg)	380	Load Weight / Truck	https://www.energy.gov/eere/fuelcells/hydrogen-tube-trailers
MJ/kg	120	Energy Intensity of Hydrogen	https://www.energy.gov/eere/fuelcells/hydrogen-storage
PJ/kg	0.00000012	= (MJ/KG)/1000000	
PJ/truck	0.00004560	= 0.00000012 * 380	
Trucks	8,771,930	= 400 / 0.00004560	
Trucks/day	24,033	= 8,771,930 / 365	

Current and planned CCUS infrastructure in Canada (mapped on Slide 58)

Infrastructure type	Notes
Active Injection Sites	These refer to sites where CO_2 is injected underground. Currently, there are six operational sites in Canada: three in Alberta and three in Saskatchewan.
Enhanced oil recovery (EOR)	These are sites where CO_2 is injected underground for EOR.
Permanent storage	These sites are where CO_2 is injected underground for permanent storage.
Pipelines	Currently there are two operational CO_2 pipelines: the Alberta Carbon Trunk Line (240 km long, 14 Mt capacity) and a cross-border Saskatchewan-US pipeline (330 km). Projects to extend the Alberta Carbon Trunk Line are planned. The Pathways Alliance also plans to develop a pipeline that extends from Cold Lake, Alberta, to the northern oil sands.
Carbon Sequestration and Evaluation Leases	These areas indicate plots of land that have been leased from the government of Alberta for the purposes of exploring storage capacity under the leased land area.
Open hub	The open hub model is an open-access model for carbon sequestration, where multiple emitters can deliver CO_2 streams for injection at the hub. For example, Clive EOR (Site 3 on the map in **Slide 58**) is a CO_2 injection hub for emissions from the Alberta Carbon Trunk Line as well as other chemical emissions.
Hydrogen	These leases are specifically for the Shell Quest Hydrogen SMR Plant, where the CO_2 produced at the plant is currently injected at a rate of 1 Mt/year, with a planned lifespan of 25 years[1] (Site 4 on the map in **Slide 58**).
Biofuels	This site is leased by Reconciliation Energy Transition Inc, who are interested in developing sustainable aviation fuel and renewable diesel with carbon sequestration.[2]
Shell Polaris and Pathways Alliance	Shell Polaris has an evaluation lease which intends to store Shell emissions captured at an industrial cluster near Edmonton.[3] Pathways Alliance is a group of six oil sands companies with net-zero initiatives. This lease is exploring storage for oil sands assets.[4]

Endnotes

Section 11

Slide 2 footnotes

1. We assume that by 2050, 50 million tonnes (megatonnes) of CO_2e can be offset by emissions and removals from land use, land use change, and forestry (LULUCF) annually. LULUCF encompasses emissions and removals mainly from forests, but also from cropland, grasslands, wetlands, settlements, and other lands. This target is more aggressive compared to other studies that employ a 100 Mt/year value for LULUCF by 2050. The lower offset potential that we attribute to LULUCF means that a greater amount of other emissions reductions need to occur across our modelled economic sectors by 2050. For an example of LULUCF estimates from other studies see Environment and Climate Change Canada 2022. "Exploring approaches for Canada's transition to net-zero emissions", https://unfccc.int/sites/default/files/resource/LTS%20Full%20Draft_Final%20version_oct31.pdf.

2. The greenhouse gas emissions estimates used throughout this report represent carbon dioxide equivalent (CO_2e, or total greenhouse gases), with the exception of when carbon dioxide emissions are captured or otherwise removed from the atmosphere (reflecting CO_2 only).

3. This gap widens still further in a climate policy rollback scenario (to a ~670 Mt/year overshoot by 2050), which we also explore in our first report. This rollback scenario reverts back to the year 2020, and thus includes all federal policy in place before the release of the federal climate plan A Healthy Environment and Healthy Economy in December 2020. The "climate policy rollback scenario" applies the Pan-Canadian Framework on Clean Growth and Climate Change carbon tax schedule.

4. In this report and for our results, we use economic sector classification based on Environment and Climate Change Canada's National Inventory Report taxonomy.

5. Notably, solar and wind deployment is highly leveraged in other studies, including non-net-zero studies as well as pathways that are heavily predicated on fossil fuel use. This suggests that the cost declines experienced and anticipated in this sector make renewables a strong contender to prioritize for generation expansion planning.

6. Import expectations are assumed to leverage the existing Canada-U.S. trade relationship and energy network (pipeline) infrastructure, however import assumptions will be challenged by the augmented domestic use of bio-based resources by the U.S. For example, the United States Inflation Reduction Act of 2022 includes incentives for production and use of RNG.

Slide 3 footnotes

1. Our net-zero target (which assumes that 50 Mt/year by 2050 that can be offset by land use, land use change, and forestry) is introduced on the previous slide. As this target is higher than net-zero target used in other studies, our results will demonstrate more aggressive requirements to achieve net zero. For example, the Government of Canada assumes that 100 Mt/year can be offset by LULUCF in 2050. See Canada's long-term strategy submitted to the United Nations Framework Convention on Climate Change, at: https://unfccc.int/sites/default/files/resource/LTS%20Full%20Draft_Final%20version_oct31.pdf). The Canadian Climate Institute assumed a similar offset potential from LULUCF in their report about reaching net-zero emissions by 2050, at 105 Mt/year in 2050, see: https://climatechoices.ca/wp-content/uploads/2021/02/Canadas-Net-Zero-Future_FINAL-2.pdf

2. 2023 has been a record-breaking year for wildfires in Canada, with an estimated 1,420 Mt of GHG emissions released so far, which is more than double all other sectoral emissions combined. (Source: Natural Resources Canada 2023 estimate as of July, National Inventory Report 2023. See: Bochove 2023. "Wildfires are set to double Canada's climate emissions this year". https://www.bloomberg.com/news/features/2023-07-26/massive-carbon-emissions-of-canada-wildfires-are-off-the-scale)

3. In Canada and globally, hydrogen is largely used as an industrial feedstock for the production of ammonia, methanol, and other chemical products, as well as in petroleum refining. In the model, hydrogen is produced for two potential uses, as a feedstock for industry or as an energy carrier/fuel to be used instead of natural gas for heating or in vehicles. Hydrogen for use as a feedstock is produced from natural gas, and the production process is decarbonized using CCS, and hydrogen produced for use as a low carbon fuel can be done through four production pathways in the model. In our results, we focus on hydrogen production for use as a fuel as (1) this is where there is a potentially significant growth in demand for hydrogen in a net-zero future, and (2) where hydrogen could play an important role in decarbonizing our energy system.

4. On Slide 45, we note that a relatively modest amount of hydrogen (100 PJ) would require an estimated ~1 to 2 million tube trailers to transport.

5. Recent studies have indicated that hydrogen gas reacts readily in the atmosphere with the same molecule responsible for breaking down methane, which is a potent greenhouse gas (Princeton University (2023). "Switching to hydrogen fuel could cause long-term climate consequences". see: https://scitechdaily.com/switching-to-hydrogen-fuel-could-cause-long-term-climate-consequences/). Hydrogen oxidation may also impact tropospheric ozone and stratospheric water vapour concentrations, which can also result in net warming (Ocko and Hamburg 2022. "Climate consequences of hydrogen emissions". see: https://doi.org/10.5194/acp-22-9349-2022).

6. We focus on the potential for liquid DAC in our modelling analysis (L-DAC), but this does not negate the future potential for different forms of DAC and other carbon dioxide removal technologies. In our model, L-DAC is sited close to geological storage basins to enable the long-term storage of carbon dioxide, though in practice DAC technology can be located agnostically of geological storage formations.

7. BECCS is associated with pathways having relatively high amounts of RNG production.

8. The DAC technology modelled is estimated to be at Technology Readiness Level (TRL) 6. TRLs 6-8 include pilot tests and successful full-scale prototypes in operational environments. Globally, BECCS deployment is currently limited to a handful of demonstration projects (largely in corn ethanol and waste-to-energy production).

9. Although not examined within our modelled results in this report, we recognize that the potential for carbon dioxide removal technologies to address historical emissions are increasingly under consideration (as per World Resources Institute (n.d.) "Carbon Removal", see: https://www.wri.org/initiatives/carbon-removal)

Slide 4 footnotes

1. In 2020, the energy consumed as electricity across the economy was about 17%.

2. Per Top Line Results, Slide 17. The presence of RNG is also indicative of the negative-emissions capture opportunity available when CCUS is combined with bioenergy, e.g. BECCS.

3. Noted here in its role as an energy carrier (i.e., fuel).

Slide 5 footnotes

1. With the exception of the hydrogen area, however even in this area federal and provincial plans vary in their approach and estimation methods, per the table shown overleaf.

2. Notwithstanding the work and planning being conducted on net zero on a municipal level across Canada. These efforts are not accounted for in this report but are making important contributions to net-zero progress.

3. Such as the time involved with approving, adding to, or building new interprovincial transmission lines; permitting and approvals for large-scale renewable energy projects; permitting and approvals for carbon capture and direct air capture facilities and associated CO_2 transportation via pipeline and storage infrastructure; enabling widespread electric vehicle fuelling/electrification infrastructure, and much more.

4. As would be implied with transformation of the entirety of the end-use energy consumption profile of Canada’s economy.

Slide 6 footnotes

1. We focus here primarily on regional-level planning, and note that steering committee work being led by Transition Accelerator to help advance this area in Canada, see: https://transitionaccelerator.ca/initiatives/electrifying-canada/

2. Natural Resources Canada (2022). "Energy Fact Book 2022-2023", see: https://natural-resources.canada.ca/sites/nrcan/files/energy/energy_fact/2022-2023/PDF/Energy-factbook-2022-2023_EN.pdf

3. Canada has a noteworthy developing hydrogen and fuel cell sector including companies such as Ballard Power Systems, Hydrogenics, New Flyer, Hydrogen Technology & Energy Corporation, Renewable Hydrogen Canada and Proton Technologies, among others.

4. The federal Emissions Reduction Plan (2022) noted an estimate of 31 Mt/year for CCUS in 2030 (or 12.9% of 239 Mt needed to achieve a 32% reduction relative to 2005, excluding LULUCF). Environment and Climate Change Canada (2022) "2030 Emissions Reduction Plan: Canada's Next Steps for Clean Air and a Strong Economy", see: https://publications.gc.ca/collections/collection_2022/eccc/En4-460-2022-eng.pdf

Slide 10 footnotes

1. Net emissions of 50 Mt CO_2e/year is set as our net-zero target for 2050. We assume that 50 Mt CO_2e/year can be removed through land use, land use change, and forestry (LULUCF). As noted, this net-zero target is more aggressive than other studies (e.g. Government of Canada) which set net-zero targets of 100 Mt/year by 2050.

2. This is based on modelling the current climate policies in the federal Emissions Reduction Plan to 2050 (Government of Canada (2022). “2030 Emissions reduction plan: clean air, strong economy”, see: https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/emissions-reduction-2030.html). This gap widens still further in a climate policy rollback scenario (to a ~670 Mt/year overshoot by 2050), which we also explore within our first report. A complete description of the modeling methodology and limitations can be found in Felder, M. and A. Hervas (2023). “Achieving net-zero pathways for Canada: what progress are we on track to make by 2050? Interim paper I”, Clean Prosperity, see: https://cleanprosperity.ca/wp-content/uploads/2023/06/Achieving-net-zero-pathways-June-2023-Clean-Prosperity.pdf.

Slide 11 footnotes

1. gTech accounts for macroeconomic dynamics such as a comprehensive coverage of economic activity, sectoral detail, labor and capital markets, interactions between regions, and representation of households. For a complete description of the modeling methodology and limitations, see our first interim paper (Felder, M. and A. Hervas (2023). “Achieving net-zero pathways for Canada: what progress are we on track to make by 2050? Interim paper I” , Clean Prosperity, see: https://cleanprosperity.ca/wp-content/uploads/2023/06/Achieving-net-zero-pathways-June-2023-Clean-Prosperity.pdf)

2. See accompanying methodology report: Navius Research (2023). “Net zero Canada methodology report”, see: https://www.naviusresearch.com/wp-content/uploads/2023/06/Methodology-Report-for-First-Clean-Prosperity-Paper-2023-06-16.pdf. Cost inputs indicated in this report (see Appendices) are drawn from this methodology report though in some instances have been updated, such as the inclusion of a low cost sensitivity for small modular nuclear reactors (SMnRs).

3. Other inputs to the model include characteristics of the model base year, fuel prices, and limits on certain materials and technologies based on the current state of knowledge. For example, limits (i.e., as percentages of production in other sectors and/or value ceilings) are set on the production of biofuels to prevent unrealistic “runaway” model results.

4. We use the term downscaling to describe the use of existing map-based information and overlaying model outputs to help identify and understand the “real-world” implications of building out model projections. Later in this report we share preliminary results of our downscaling work underway for CCUS.

Slide 12 footnotes

1. **The High-Electrification** (referred to as Electrification) pathway reflects a future scenario in which electricity becomes cost-competitive enough to replace natural gas and other fossil fuels in a wide range of energy uses, such as process heat, buildings, and transportation. In this future, electricity is dominant and there is no restriction on how it is produced. Low-carbon electricity options available include wind and solar power, new large nuclear and SMnRs, as well as fossil-fuel generation with CCUS.

2. **The High Electrification with Renewables pathway** (HIgh Renewables) is envisioned as a future in which targets for high electrification are primarily met with renewables (e.g., existing hydro, and new wind, solar, and biomass energy). It is assumed that increased electricity demand is not met through nuclear power, either new larger nuclear plants or SMnR technologies. This pathway is distinctive in that we apply an explicit and managed wind-down of oil and gas production by 2050 to achieve near-zero fossil-fuel production.

3. **Bioenergy** In this Bioenergy pathway, biofuels (both liquid and gaseous forms) become more competitive with their fossil-fuel counterparts and more accessible and applicable to selected end uses. Although electrification still powers much of the economy, natural gas continues to play a prominent role and leverages a natural gas stream composed largely of RNG. Bioenergy with carbon capture and storage is considered a generally-available technology option.

4. **Hydrogen** For the Hydrogen pathway, future hydrogen production and fuel-cell technology become cost-competitive enough for hydrogen to be used for energy storage, and as a replacement fuel in transportation and in industry. Fuel switching offers an attractive alternative for those sectors that present electrification challenges.

5. **Fossil with Carbon Capture, Utilization and Storage.** The Fossil with CCUS pathway envisions an economy primarily based on fossil fuels through the increased use of natural gas and oil, with fully decarbonized upstream production through engineered carbon capture. In this fossil-based future (which also allows for nuclear), Canada continues to rely heavily on combustion applications such as in transportation and heat, which would be offset by CCUS and DAC.

6. This is a more conservative assumption concerning LULUCF compared to some other studies, as noted previously on Slide 3, Footnote 2. For example, the Government of Canada uses 100 Mt CO_2e/year as its net-zero target for 2050 in its long-term strategy submitted to the United Nations Framework Convention on Climate Change. (Environment and Climate Change Canada (2022). "Exploring approaches for Canada's transition to net-zero emissions", see: https://unfccc.int/sites/default/files/resource/LTS%20Full%20Draft_Final%20version_oct31.pdf)

7. The baseline policy assumptions across all our net-zero pathways modelling include provincial policy legislated as of November 2021, and that legislated federal carbon pricing and climate-policy regulations are reverted to those in place before the plan *A Healthy Environment and a Healthy Economy* was released in December 2020. We adopted this "rollback" baseline so as to be conservative in our emissions reduction starting point, and not presuppose that all the policies in the current federal Emissions Reduction Plan (ERP) will be executed in full and on time (by 2030). This aligns with the recent findings of the Commissioner of the Environment and Sustainable Development, who found that of the 80 measures in the ERP, nearly half do not have deadlines for achievement. See: https://www.oag-bvg.gc.ca/internet/English/parl_cesd_202311_06_e_44369.html. This said, we note that the policy starting point employed is somewhat moot given the aggressive 2050 net-zero constraint that we have imposed on the model.

8. This constraint was applied to identify and evaluate the implications of a fossil fuel phaseout. The High Renewables pathway is included in the model as a bookend pathway, as is the Fossil with CCUS pathway.

9. Further explanation and detail on these parameters (e.g. levels set for high, low and REF) are detailed in **Appendix A.**

Slide 14 footnotes

1. Slide 18 defines the elements of each pillar that are the focus of the subsequent slides, and explains how they work to achieve emissions reduction.

Slide 15 footnotes

1. The model is designed to take advantage of available technologies to reduce emissions while supporting economic growth. It also simulates choice in technological adoption and incorporates behavioural realism into decision making. Therefore, the pathway results are reflective of the likely paths to achieve net-zero emissions given the current and emerging technologies with their associated cost parameters. Essentially there is a heterogeneity function in gTech that ensures a mix of technologies are maintained even if one is less costly than another. This framework is therefore flexible and dynamic in the sense that it maintains the objective of identifying feasible solutions that lead to the best economic outcomes without favouring any particular technology, while leaving room for other possible solutions, including more transformational system approaches.

2. However, they may be analyzed further in future research. We also note that there are other trends and changes that can lead to emissions reduction that we do not analyze in detail in this report. For example, advances in technological energy efficiency are not conceptualized as a separate pillar or supporting element as they are can apply to any of the pillars, impacting the overall scale of deployment needed in any net-zero pathway (in a similar way to other factors that impact energy demand, such as population and economic growth).

Slide 16 footnotes

1. Most net-zero studies, even those with more favourable input costs for hydrogen, expect hydrogen fuel to come in around this range of final energy use. This is explored later in this report.

2. Ranging from ~ 22x to 50x current sequestration (using current sequestration of 4 Mt, and comparing this value to our pathway projections for CCUS anticipated by 2050).

3. In 2020, the energy consumed as electricity across the economy was about 17%.

4. Per Top Line Results, Slide 17. The presence of RNG is also indicative of the negative-emissions capture opportunity available when CCUS is combined with bioenergy, e.g. BECCS.

Slide 17 footnotes

1. The production phaseout constraint leads to less consumption in part due to declining consumption of fossil fuels in oil and natural gas production.

2. Results show in this figure are gTech results. IESD predicts less RNG use in the electricity generation than gTech due to two key dynamics: 1) IESD better represents the potential for renewables leading to more renewable generation; and 2) gTech accounts for the economy at large, considering the cost of CO_2 abatement to comply with net-zero in every sector. Using RNG with CCUS in the electricity sector leads to negative GHG emissions, which means that (in the model) other sectors with higher emissions abatement costs need to reduce emissions less.

Slide 18 footnotes

1. Notwithstanding the potential impact of the Jevons Paradox, which states that the economical use of fuel results not in diminished consumption, but in an overall increase (Organisation for Economic Co-operation and Development (2022). "The Jevons Paradox and rebound effect: are we implementing the right energy and climate change policies?", see: https://www.oecd-forum.org/posts/the-jevons-paradox-and-rebound-effect-are-we-implementing-the-right-energy-and-climate-change-policies)

2. In theory, the production of RNG captures CO_2e (i.e. growing feedstocks and capturing landfill gas) that would otherwise be released into the atmosphere, making it carbon-neutral. However, because production requires energy and land, on a life cycle basis this would be low-carbon rather than completely carbon neutral.

3. RNG is often deployed as part of BECCS (bioenergy with carbon capture and storage), which is the process of capturing and permanently storing carbon dioxide from processes where biomass is converted into fuels or directly consumed for energy generation. Since plants absorb carbon dioxide as they grow, BECCS is way of removing carbon dioxide from the atmosphere, resulting in net-negative emissions. This makes the RNG pillar unique in that RNG deployment yields emissions reduction through avoided consumption of fossil-derived natural gas *and* carbon sequestration when paired with CCUS. Conversely, reduced deployment of RNG can mean that emissions reductions will have to be made to compensate for the unrealized BECCS opportunity *in addition to* using more fossil fuels instead of RNG.

Slide 20 footnotes

1. For example, in our results we see the highest degree of electrification take place in the Electrification and High Renewables pathways, which assume more competitive electric technologies. However, additional support can help to further lower costs associated with electrification, making it even more competitive against other means of reducing emissions such as DAC. Furthermore, more electrification would likely be required in cases where other decarbonization options, such as second-generation RNG, are found to be not viable at the required scale. Importantly, the model lacks foresight, which can lead to the installation of fossil-based technologies at a given point in time even though the carbon price is set to keep rising in the following years. With foresight, a different choice, such as favouring electric technology, might have been made instead.

2. End-use demand is lower than total electricity generation due to electricity being lost in interprovincial transmission or during storage (i.e., if a battery is charged but the stored electricity is not used, a share of the charge is lost every hour), and a portion of electricity being exported to the United States.

3. Early estimates point to substantial energy consumption by artificial intelligence technologies. For example, in one source, ChatGPT has been estimated to require as much as 1 GWh/day to process queries (equivalent to the daily energy consumption of about 33,000 households in the United States per the article). Significant amounts of energy are also required to train large language models (University of Washington (2023). “Q&A: UW researcher discusses just how much energy Chat GPT use”, see: https://www.washington.edu/news/2023/07/27/how-much-energy-does-chatgpt-use/). Another source suggests that powering artificial intelligence can, in the future, use more power than some small countries. (de Vries, A. (2023). “The growing energy footprint of artificial intelligence”, Joule, see: 10.1016/j.joule.2023.09.004)

4. For example, the use of small modular nuclear reactors (SMnRs) is being explored for generating heat for industrial applications in hard-to-decarbonize sectors. (Melton, N. and A. Marstokk (2022). “Potential of small modular reactors in hard-to-decarbonize industries”, see: https://www.naviusresearch.com/publications/pollution_probe_smrs/). SMnR-generated process heat plays a minor role in lowering manufacturing emissions in our Electrification and Fossil with CCUS pathways, with cost remaining a significant barrier to widespread implementation.

Slide 21 footnotes

1. Recent work by the Canadian Climate Institute determined that for most Canadian households heat pumps are a lower cost option for heating and cooling homes than air conditioners and gas heaters. They can therefore carry benefits for affordability on top of emissions reductions, with little to no required infrastructure buildout. (Canadian Climate Institute (2023). “Heat pumps pay off: unlocking lower-cost heating and cooling in Canada”, see: https://climateinstitute.ca/reports/heat-pumps-canada/)

2. 9 TWh is ~1% of total energy consumed in this sector in 2020. This shift reflects potentially the largest increase in electricity use of all sectors (~108 to 155 TWh), and leads to large emissions reductions due to the displacement of refined petroleum (currently the primary energy source in this sector). The Buildings sector also reflects a potentially large increase (85 to 112 TWh), but from a higher starting point of 288 TWh in 2020 (as noted).

Slide 22 footnotes

1. Although the High Renewables pathway shows the highest degree of electrification for this sector (35%), this pathway assumes an oil and gas production phaseout which results in a steep decline of overall energy consumption in the sector. In 2050, oil and gas production via this pathway declines to about 4% of 2020 production. Reduced production associated with the oil and gas phase-out, relatively low DAC adoption, as well as efficiency gains from electrification lead to lower total electricity consumption in the High Renewables pathway compared to the others.

2. Electricity in light manufacturing makes up roughly the same or a lower proportion of total energy consumption in 2050 compared to 2020.

3. These sectors use low- and high-temperature heat for many processes. While low-temperature heat can be electrified, electrification of high-temperature heat is a challenge. Emissions from high-temperature heat can be reduced through use of biofuels/RNG, hydrogen, and in some cases CCUS. Recent studies have also looked at the potential of using green hydrogen (International Renewable Energy Agency (2023), "Innovation landscape for smart electrification") as well as small modular nuclear reactors to fulfill the demand for high-temperature heat. In our results, we see limited adoption of SMnRs in manufacturing in the Fossil with CCUS and Electrification pathways. Notably, the costs associated with producing heat from SMnRs are considerably lower than than those of producing electricity from SMnRs (Appendix Slide 76), underscoring the potential of this technology for decarbonization beyond (or in combination with) electrification (Navius Research for Pollution Probe (2021). "Identifying opportunities for small modular reactors to reduce greenhouse gas emissions in Canadian industry", see: https://www.naviusresearch.com/wp-content/uploads/2022/06/SMR-GHG-Reduction-Potential_2021-12-03.pdf)

4. If given a clear direction from government regarding future carbon price increases and/or other net-zero policies, we would likely see less addition of fossil-based technologies and more adoption of alternatives such as electric technologies. Because the model is myopic, the results are not reflective of future expectations which can play a significant role in decision-making and are likely underestimating electrification potential from this standpoint. This further highlights the importance of clear and forward-looking policies in supporting technological shifts.

Slide 23 footnotes

1. The graph shown reflects results from the Navius IESD model. Less renewables and more RNG with CCUS are seen in the results from the Navius gTech model.

2. When paired with CCUS, RNG-based generation can be considered net carbon-negative. This has implications for the rest of the energy economy since net-negative emissions in the electricity sector create “room” for emissions in other sectors. Conversely, the less RNG+CCUS we see in the electricity sector, the more necessary it is to drive reductions in other sectors.

3. Reliability of a technology pathway is fixed in gTech and IESD, meaning that every system simulated is reliable. In other words, the model will not simulate a net-zero pathway that includes unreliable outcomes such as power outages, but instead will require investment in sufficient solutions to ensure reliability, such as energy storage, the impacts of which will be incorporated in the resulting cost of that pathway. The reliability of a given net-zero energy pathway is therefore incorporated into the cost of that pathway.

Slide 24 footnotes

1. Canada Energy Regulator (2023). "Canada's Energy Future 2023", see: https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/canada-energy-futures-2023.pdf

2. Electric Power Research Institute (2021). "Canadian National Electrification Assessment", see: https://www.epri.com/research/products/000000003002021160

3. The cost of photovoltaic (PV) panels has fallen dramatically over the last 10-15 years. The National Renewable Energy Laboratory of the United States (NREL) estimates that the cost of utility-scale solar PV has declined from around $5 USD per 100 MW in 2010 to around $1 USD in 2020 (Source: National Renewable Energy Laboratory (2021). "Documenting a decade of cost declines for PV systems", see: https://www.nrel.gov/news/program/2021/documenting-a-decade-of-cost-declines-for-pv-systems.html). At the same time, module efficiency and longevity have steadily increased. Cost of wind systems has also declined, but not nearly at the same pace (Office of Energy Efficiency and Renewable Energy (2021). "Experts predict 50% lower wind costs than they did in 2015", see: https://www.energy.gov/eere/wind/articles/experts-predict-50-lower-wind-costs-they-did-2015-0)

4. New large hydro is expected in some modelling scenarios from Environment and Climate Change Canada (Environment and Climate Change Canada (2022). "Exploring approaches for Canada's transition to net-zero emissions", see: https://unfccc.int/sites/default/files/resource/LTS%20Full%20Draft_Final%20version_oct31.pdf) and the Canada Energy Regulator (Canada Energy Regulator (2023). "Canada's Energy Future 2023", see: https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/canada-energy-futures-2023.pdf).

5. There are maintenance and other operational costs associated with hydro electricity, which are accounted for in our model.

6. Geothermal and offshore wind do not appear in our results due to high costs. Geothermal is modelled in IESD (but not in gTech).

7. In our model, new nuclear electricity generation tends to be outcompeted by the comparatively cheaper solar, wind, and natural gas combustion with CCUS, even when lower capital costs are modelled form small modular reactors (~40% lower than the base cost assumption, see Appendix Slide 76).

8. SMnR refers to small modular nuclear reactor. A consideration that is not examined in this report is nuclear generation capacity beyond 2050. Most nuclear reactors in Canada are undergoing or are set to undergo refurbishment over the next decade, which will extend their operating life for approximately 30 years, at which point they will be retired. The current nuclear capacity will therefore need to be replaced beginning around 2050 in addition to other expansion in electricity generation. (World Nuclear Association (2023). "Nuclear Power in Canada", see: https://world-nuclear.org/information-library/country-profiles/countries-a-f/canada-nuclear-power.aspx)

9. Canada has recently issued an action plan on small modular nuclear development (Government of Canada (2023). "Canada's Small Modular Reactor Action Plan ", see: https://smractionplan.ca/). The Ontario government is also working with Ontario Power Generation to build four SMnR units to produce a total of 1,200 MW of electricity (Government of Ontario (2023). "Ontario building more small modular reactors to power province's growth", see: https://news.ontario.ca/en/release/1003248/ontario-building-more-small-modular-reactors-to-power-provinces-growth)

Slide 25 footnotes

1. See Slide 82 in the Appendix for sources shown in this graph. Values shown here are approximate, with some estimated from graphs or discussions in reports (e.g., Environment and Climate Change Canada (2022). “Exploring approaches for Canada’s transition to net-zero emissions”, see: https://unfccc.int/sites/default/files/resource/LTS%20Full%20Draft_Final%20version_oct31.pdf) and others calculated from publicly available dashboards (e.g., Pathways) based on limited known assumptions. As such, they may not represent the full range of values that may have been covered in these studies.

Slide 26 footnotes

1. See Slide 82 in the Appendix for sources shown in this graph.Values shown here are approximate, with some estimated from graphs or discussions in reports (e.g., Environment and Climate Change Canada (2022). "Exploring approaches for Canada's transition to net-zero emissions", see: https://unfccc.int/sites/default/files/resource/LTS%20Full%20Draft_Final%20version_oct31.pdf) and others calculated from publicly available dashboards (e.g., Pathways) based on limited known assumptions. As such, they may not represent the full range of values that may have been covered in these studies.

Slide 27 footnotes

1. As also identified by the Electrifying Canada task force, now led by the Transition Accelerator (International Institute for Sustainable Development (2022). “Scaling up electricity”, see: https://www.iisd.org/system/files/2022-05/scaling-up-clean-electricity-en.pdf).

2. A recent paper by the Canadian Climate Institute details the main institutional challenges in the Canadian electricity sector (Canadian Climate Institute (2022). “Electric federalism”, see: https://climateinstitute.ca/wp-content/uploads/2022/05/Electric-Federalism-May-4-2022.pdf).

3. Some utilities may plan for some of the drivers discussed in this paper.

4. Due to the presence of available geological storage and infrastructure to sequester the captured carbon, which is employed in our model to achieve our net-zero target.

5. In the Fossil with CCUS pathway, Alberta is expected to generate 163 TWh of electricity a year by 2050. Situating the amount of DAC projected by this pathway in Alberta alone would amount to an additional 50 TWh of demand, equivalent to 30% of the province’s anticipated generation.

Slide 28 footnotes

1. With some exceptions. Quebec shows less of an increase as the model assumes increased demand will be met by a decrease in electricity exports. The model also anticipates a decline in generation for Atlantic Canada, in part due to reported hydroelectric generation values which require further refinement.

2. Total electricity generation in Canada in 2019 was 632 TWh, per the Canada Energy Regulator (Canada Energy Regulator (2023). "Provincial and territorial energy profiles - Canada", see: https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-canada.html)

3. Total electricity generation in Canada for 2050 in the Electrification pathway is approximately 1,116 TWh. This pathway is selected as it represents a higher estimate for the electricity generation anticipated for 2050.

Slide 29 footnotes

1. Not all electricity estimates are easily converted, as studies make use of varied ways to estimate projections (e.g. % peak demand vs. TWh of anticipated generation).

2. B.C. Hydro and Power Authority (2023). “2021 Integrated Resource Plan”, see: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/integrated-resource-plan-2021.pdf. Lower estimate is the reference base load forecast; higher estimate is the accelerated electrification scenario.

3. Fortis B.C. (2020). “Pathways for British Columbia to achieve its GHG reduction goals”, see: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/guidehouse-report.pdf

4. Alberta Electric System Operator (2021). “Long-term outlook”, see: https://www.aeso.ca/assets/Uploads/grid/lto/2021-Long-term-Outlook.pdf

5. Independent Electricity System Operator (2022). “Preparing for the electricity system of tomorrow”, see: https://ieso.ca/-/media/Files/IESO/Document-Library/corporate/strategy/IESO-Corporate-Strategy-2022-2027.ashx

6. Edom, E., Langlois-Bertrand, S., Mousseau, N. (2022). A Strategic Perspective on Electricity in Central and Eastern Canada, Institut de l’énergie Trottier, Polytechnique Montréal, see: https://iet.polymtl.ca/wp-content/uploads/delightful-downloads/WhitePaper_strategic-perspective-electricity-central-eastern-canada-1.pdf
Calculated with 2016 demand values obtained from the Independent Electricity System Operator (Independent Electricity System Operator (2023). “2016”, see: https://www.ieso.ca/en/Corporate-IESO/Media/Year-End-Data/2016), Hydro Quebec (Hydro Quebec (2016). “Annual Report 2016”, see: https://www.hydroquebec.com/data/documents-donnees/pdf/annual-report-2016.pdf)

7. Hydro-Quebec (2022). “Strategic plan 2022-2026”, see: https://www.hydroquebec.com/data/documents-donnees/pdf/strategic-plan.pdf?v=2022-03-24

Slide 30 footnotes

1. CCUS systems also require energy to operate. However, because they are connected to the (often fossil-based) power systems of individual point sources, they are not included here as drivers of electricity demand. Energy consumption by CCUS still requires consideration with respect to grid planning however. For example, if CCUS is implemented at natural gas plants, the energy required to operate CCUS will effectively reduce the efficiency of the plants.

2. While any of the drivers may come into play in non-net-zero scenarios, some are more likely to emerge with push from climate policy. For example, production of electricity-derived fuels like green hydrogen is more likely if policy encourages significant clean hydrogen production and use.

3. Notwithstanding the Jevons Paradox, where the economical use of fuel results not in diminished consumption, but in an overall increase due to a “cheaper” energy service driving its own demand combined with an increase in other types of consumption due to monetary savings (Organisation for Economic Co-operation and Development (2022). “The Jevons Paradox and rebound effect: are we implementing the right energy and climate change policies?”, see: https://www.oecd-forum.org/posts/the-jevons-paradox-and-rebound-effect-are-we-implementing-the-right-energy-and-climate-change-policies).

4. Additional computation may be needed in scenarios where automation is encouraged as part of a sector transformation (for example, as a strategy to shift away from personal vehicles). For example, in addition to AI-based platforms like ChatGPT, computing requirements may become a significant factor in transportation if autonomous vehicles become widely adopted. (Zewe, A. (2023). “Computers that power self-driving cars could be a huge driver of global carbon emissions”, MIT News Office, see: https://news.mit.edu/2023/autonomous-vehicles-carbon-emissions-0113). We do not currently account for these computational requirements or transformational shifts in the model.

Slide 31 footnotes

1. Among other efforts, we will build on recent work by the International Institute for Sustainable Development and the Transition Accelerator that seek to develop sector-specific frameworks for electrification, see: https://www.iisd.org/projects/electrifying-canada

2. Currently, relatively cheap natural gas challenges the business case for switching to electricity.

3. Other challenges for the transportation sector include a constrained vehicle supply and limited vehicle options (particularly for medium- and heavy-duty fleets), as well as operational and implementation challenges (e.g., capital expenditure and widely-available financing for electric vehicles).

4. Because the model is not spatial, these issues need to be addressed separately through downscaling, which involves the use of mapping data and geographic information system (GIS) tools.

Slide 33 footnotes

1. RNG is readily substitutable for fossil-derived natural gas, without the need for separate transport infrastructure. One reason why RNG and liquid biofuels are attractive in the model is because they do not require technological retrofits. In our results RNG can appear as blended with natural gas (e.g., in natural-gas-based heating). An added benefit of RNG is that it can also be stored to meet peak demand.

2. Our net-zero target (which assumes that 50 Mt/year by 2050 that can be met from land use, land use change, and forestry) was introduced previously. As this reduction target is higher than net-zero target used in other studies, our results will demonstrate more aggressive requirements to achieve net zero. For example, the Government of Canada assumes that 100 Mt/year can be met by LULUCF in 2050 (Environment and Climate Change Canada (2022). “Exploring approaches for Canada’s transition to net-zero emissions”, see: https://unfccc.int/sites/default/files/resource/LTS%20Full%20Draft_Final%20version_oct31.pdf). The Canadian Climate Institute assumed a similar offset potential from LULUCF in their report about reaching net-zero emissions by 2050, at 105 Mt/year in 2050 (Canadian Climate Institute (2021). “Canada’s net zero future”, see: https://climatechoices.ca/wp-content/uploads/2021/02/Canadas-Net-Zero-Future_FINAL-2.pdf)

3. A key reason why high amounts or RNG are deployed in our model is that the model chooses bioenergy with carbon capture and storage as a lower-cost option to offset certain emissions that remain in the economy. Considerations associated with high RNG deployment are discussed later in this section.

4. We also note that given the potentially high cost of RNG, using it for applications like home heating may not be advisable as cheaper and more widely available solutions can be deployed for this purpose. District heating with biomass cogeneration has been suggested by stakeholders as an important alternative to explore, as a component of decarbonization that addresses the opportunity to utilize waste heat. For example, the Swedish municipal utility Göteborg Energi has shifted its focus on wood-to-RNG technology in favour of biomass combined heat and power plants with district heating (Bioenergy Insight (2023), “Göteborg Energi makes €217.7m biomass boiler investment”, see: https://www.bioenergy-news.com/news/goteborg-energi-makes-e217-7m-biomass-boiler-investment/)

5. Globally, BECCS deployment is currently limited to a handful of demonstration projects (largely in corn ethanol and waste-to-energy production), however some studies have indicated the potential for profitable RNG production with CCS. In a recent study for California, a favorable policy environment scenario suggests that RNG production with CCS could enable 4 million tons of CO_2 sequestration in 36 sites (equivalent to Canada’s current-day total carbon sequestration), and that 130 PJ of RNG could be produced annually from 121 facilities. (Wong et al. (2022). “Market potential for CO2 removal and sequestration from renewable natural gas production in California”, Environment, Science and Technology, see: https://pubs.acs.org/doi/full/10.1021/acs.est.1c02894)

6. Recognizing the need to develop a sustainable bioeconomy in Canada, the federal government has in recent years rolled out supports for clean fuel and forest sector innovation. Funding through programs including the Clean Fuels Fund, the Investments in Forest Industry Transformation, and the Forest Innovation Program, has been extended to projects aiming to produce renewable energy and sustainable bioproducts, explore BECCS in forest sector operations, establish reliable biomass supply chains, and other development in the bio-sector. (Natural Resources Canada (2022). “Clean Fuels Fund”, see: https://natural-resources.canada.ca/climate-change/canadas-green-future/clean-fuels-fund/23734; Natural Resources Canada (2023). “Investments in Forest Industry Transformation (IFIT)”, see: https://natural-resources.canada.ca/science-and-data/funding-partnerships/opportunities/forest-sector/investments-forest-industry-transformation/13139; Natural Resources Canada (2023). “Forest Innovation Program”, see: https://natural-resources.canada.ca/science-and-data/funding-partnerships/opportunities/forest-sector/forest-innovation-program/13137)

7. Nance, E., et al. (2023). “The burning question: addressing harvest residue management in B.C.”, see: https://www.canadianbiomassmagazine.ca/the-burning-question-addressing-harvest-residue-management-in-b-c/

Slide 34 footnotes

1. In the model, first generation RNG is derived from organic wastes (e.g., food waste and manure) and landfill gas. RNG from wood and crop residue is considered to be second generation, departing from some sources that consider crop residue as first generation or "conventional" (such as Torchlight Bioresources (2020). "Renewable natural gas (biomethane) feedstock potential in Canada", see: https://www.enbridge.com/~/media/Enb/Documents/Media%20Center/RNG-Canadian-Feedstock-Potential-2020%20(1).pdf).

For further information see our modelling methodology report (Navius Research (2023), "Net zero Canada methodology report", see: https://www.naviusresearch.com/wp-content/uploads/2023/06/Methodology-Report-for-First-Clean-Prosperity-Paper-2023-06-16.pdf)

Slide 35 footnotes

1. A key reason why the model is adopting RNG is to produce negative emissions to achieve net zero via BECCS. Lower DAC cost assumptions and electricity cost assumptions can lead to scenarios with lower RNG production and use. Instead of BECCS, our Fossil pathway relies primarily on DAC to achieve net zero, at -259 Mt a year in 2050.

2. On imports, the American Gas Foundation (American Gas Foundation (2019). “Renewable sources of natural gas: supply and emissions reduction assessment, December 2019”) estimated 630-857 PJ of RNG potential in the US in 2050 under non-aggressive scenario and over 1500 PJ under aggressive scenarios (National Research Energy Laboratory (2013), “Energy analysis: biogas potential in the United States”). This potential varies greatly between U.S. states, and estimates are for first-generation (organic waste, landfills, etc.). NREL (2013) estimates ~431 PJ from organic waste; if lignocellulosic biomass sources are used potential could reach 4556 PJ (per Fortis (2022). “B.C. renewable and low-carbon gas supply potential study”, see: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/renewable-gas-study-final-report-2022-01-28.pdf)

3. The U.S. *Inflation Reduction Act a*nd its potential implications for modelling results (such as for RNG imports) are to be further explored in our next reporting phase.

Slide 36 footnotes

1. TorchLight Bioresources (2020). "Renewable natural gas (biomethane) feedstock potential in Canada", see: https://www.enbridge.com/~/media/Enb/Documents/Media%20Center/RNG-Canadian-Feedstock-Potential-2020%20(1).pdf Other Canadian studies looking at RNG production potential largely align with TorchLight's estimates, with variations depending on how potential is calculated and which feedstocks and parameters are included/excluded.

2. Forest management is an important emerging area of study in light of the increasing frequency and severity of wildfires across Canada. Synergies with biofuel production can be beneficial to explore as part of the development of more effective wildfire management strategies. Maintaining soil quality, soil productivity, water and riparian zones, forest health and biodiversity also need to be considered in any work looking to make further use of residue removal.

3. According to data from satellite monitoring service of the European Union (per: Milman, O. (2023). "After a record year of wildfires, will Canada ever be the same again?", see: https://www.theguardian.com/world/2023/nov/09/canada-wildfire-record-climate-crisis)

Slide 37 footnotes

1. This report notes the production of RNG as a part of primary biomass uses (Figure 7.9, pg. pg. 88). We do not include this estimate due to uncertainty if this equates to how much RNG is produced. (Langlois-Bertrand, S. et al. (2021) “Canadian Energy Outlook 2021 - Horizon 2060”, Institut de l’energie Trottier, see: https://iet.polymtl.ca/wp-content/uploads/delightful-downloads/CEO2021_20211112.pdf)

Slide 38 footnotes

1. Source: Canada Energy Regulator 2023. Current and planned RNG projects in Canada. (Canada Enegy Regulator (2023). “Market snapshot: two decades of growth in renewable natural gas in Canada”, see: https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2023/market-snapshot-two-decades-growth-renewable-natural-gas-canada.html#t1 There is also a plant by Enerkem in Edmonton, Alberta in initial operation, using refuse-derived fuel (RDF). A second plant in Canada is in planning stage.

2. The Bioenergy pathway has the highest consumption, as well as one of the highest domestic production estimates for RNG of our net-zero pathways.

Slide 39 footnotes

1. FortisBC also plans to procure 30 GJ of biogas, as prescribed by the 15% renewable gas target in the provincial government's *CleanBC* Roadmap (Government of British Columbia, "Roadmap to 2030", see: https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_roadmap_2030.pdf).

2. These results signal that the model may be over-leveraging second-generation RNG and overestimating the availability of agricultural residue in the prairies. We note however that the modelled RNG production costs are very similar to first generation costs that are not implicitly represented in the model (e.g., using energy crops and anaerobic digestion). These higher cost first generation pathways may have more limited resource availability due to competition with the food system. In the model, this results in the second generation pathway having much higher feedstock availability and potential than first generation RNG and similar cost compared to higher cost first generation RNG production.

3. Based on analysis from TorchLight Bioresources (2020). "Renewable natural gas (biomethane) feedstock potential in Canada", see: https://www.enbridge.com/~/media/Enb/Documents/Media%20Center/RNG-Canadian-Feedstock-Potential-2020%20(1).pdf

4. There can be high interannual variability in the availability of crop residues in these regions.

Slide 40 footnotes

1. TorchLight Bioresources (2020). “Renewable natural gas (biomethane) feedstock potential in Canada”, see: https://www.enbridge.com/~/media/Enb/Documents/Media%20Center/RNG-Canadian-Feedstock-Potential-2020%20(1).pdf

2. Fortis (2022). “B.C. renewable and low-carbon gas supply potential study”, see: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/renewable-gas-study-final-report-2022-01-28.pdf

3. A limited, fixed percentage of forest residue, which is linked to forestry activity, is assumed to be available for energy production, accounting for current uses of residue including residue that is left behind to recycle nutrients back to the soil. This percent estimate assumption has not been provided by the modellers. Mill residue is assumed to be unavailable for RNG production.

4. Regional differences based on feedstock availability, energy prices, trade and demand are accounted for. Geographical detail within provinces are not represented within the model as this information is aggregated on the provincial scale.

5. A fixed percentage of agricultural residue, which is linked to activity in agriculture, is assumed to be available for energy production, accounting for current uses of residue (including animal bedding and nutrient recycling).

Slide 41 footnotes

1. Geographic constraints include proximity of RNG production facilities and feedstock suppliers to infrastructure (e.g., roads, pipelines) and demand centres. Feedstock scarcity in particular, followed by logistics and transport costs, can be highly material for feedstock supply chains, which are not well represented in the model. Location of RNG development also carries implications for land management and land tenure, especially for second-generation feedstocks.

2. Additional challenges with RNG production, including the early market barrier problem, and competitiveness of RNG with other fuels, also require further examination. RNG processing faces a “chicken-or-egg” early market barrier problem, where facilities need access to a secure feedstock supply chain to de-risk infrastructure investment. At the same time, feedstock suppliers need a secure market for their product. With respect to RNG competitiveness, currently a large part of the RNG in our model goes to heating applications, especially to support high-heat industrial processes that are difficult to electrify. However, RNG is currently not competitive with natural gas (but can be competitive with diesel), which raises further questions about the best regional and sectoral fit for RNG deployment and potential trade-offs with other options to reduce emissions.

3. For example, a recent Californian study employed a spatial-based approach to show that, under current state and federal policy incentives, RNG with CCS can avoid 12.4 Mt CO_2e/year, or 3% of California’s 2018 CO_2 emissions, of which 2.9 Mt CO_2/year are captured and sequestered. (Wong, J., J. Santoso, M. Went, and D. Sanchez (2022) “Market Potential for CO_2 Removal and Sequestration from Renewable Natural Gas Production in California” Environmental Science & Technology 2022 *56* (7), 4305-4316, see: https://pubs.acs.org/doi/full/10.1021/acs.est.1c02894)

Slide 43 footnotes

1. In our modelling, production of feedstock hydrogen shifts away from largely unabated SMR (grey) by 2050. In our net-zero pathways most of the hydrogen feedstock production switches to the blue (SMR with CCUS) production pathway (with some green, depending on the net-zero scenario).

2. We note the gTech model also accounts for all hydrogen produced and consumed (whether for use as a feedstock or as an energy carrier). The transition of hydrogen feedstock production from grey to cleaner forms of production is also captured in the model.

3. We also note that Canada has a recognized hydrogen and fuel cell sector, which includes companies such as Ballard Power Systems, Hydrogenics, New Flyer, Hydrogen Technology & Energy Corporation, Renewable Hydrogen Canada and Proton Technologies, among others.

4. These studies estimate hydrogen use between 4% and 9% of total energy consumption in 2050.

5. Natural Resources Canada (2020). “Hydrogen Strategy for Canada”, see: https://natural-resources.canada.ca/sites/nrcan/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

6. ATR refers to autothermal reformation (described on the following slide).

7. The model also accounts for the fact that there is a limit to how much H_2 can be blended into existing pipelines.

8. Discussed further on Slide 45.

Slide 44 footnotes

1. Canada is one of the top ten global hydrogen producers (Natural Resources Canada (2020). "Hydrogen Strategy for Canada", see: https://natural-resources.canada.ca/sites/nrcan/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf)

2. This 'grey' hydrogen production, which is used as an industrial feedstock to make fertilizer nitrogen and in the petrochemical sector, results in GHG emissions of about 9 kg CO_2e/kg H_2. (Layzell, D.B. et al. (2020). "Towards net-zero energy systems in Canada: a key role for hydrogen", The Transition Accelerator, see: https://transitionaccelerator.ca/wp-content/uploads/2020/09/Net-zero-energy-systems_role-for-hydrogen_200909-Final-print-1.pdf)

3. Commonly refers to Steam Methane Reforming or Autothermal Reforming (SMR, ATR), which are industrial process that converts natural gas into hydrogen at high temperature. Autothermal reforming is a process where more CO_2 can be captured in the process stream. (e.g. Gorski, J., Jutt, T., and K.Tam Wu (2021). "Carbon intensity of blue hydrogen production", Pembina Institute, see: https://www.pembina.org/reports/carbon-intensity-of-blue-hydrogen-revised.pdf

4. Reported as natural gas to produce hydrogen (Statistics Canada (2023). "Report on energy supply and demand in Canada: explanatory information", see: https://www150.statcan.gc.ca/n1/pub/57-003-x/57-003-x2023001-eng.htm)

Slide 45 footnotes

1. gTech simulates energy consumption and abatement pathways for hydrogen feedstock production. Hydrogen is used as a feedstock by multiple sectors, such as petroleum refining, fertilizer manufacturing, upgrading and biofuels production. The model includes the following feedstock hydrogen production pathways: steam methane reformation, steam methane reformation and CCS, and using still gas. Feedstock hydrogen produced through steam methane reformation can be abated through deployment of carbon capture and storage.

2. For example, see NREL 2023. Hydrogen blending as a pathway toward U.S. decarbonization. (National Renewable Energy Laboratory (2023). “Hydrogen blending as a pathway towards U.S. decarbonization”, see: https://www.nrel.gov/news/program/2023/hydrogen-blending-as-a-pathway-toward-u.s.-decarbonization.html)

3. See Appendix Slide 78. Lower input costs for hydrogen production (which were applied within the Hydrogen technology pathway) are employed for ATR/SMR and electrolysis, compared to results from other studies.

4. Internal calculations, Navius Research - see Appendix Slide 84. This estimate presumes that hydrogen end-use is distributed (made at a point source and distributed to FCEV refuelling stations) instead of centralized (produced on demand and transported short distances to industrial users).

5. Recent studies have indicated that hydrogen gas reacts readily in the atmosphere with the same molecule responsible for breaking down methane, which is a potent greenhouse gas. Researchers have posited that if the level of hydrogen emissions (mainly through leakage) surpasses a specific threshold, it can result in an accumulation of methane in the atmosphere, leading to long-term climate consequences. (Princeton University (2023). “Switching to hydrogen fuel could cause long-term climate consequences”, see: https://scitechdaily.com/switching-to-hydrogen-fuel-could-cause-long-term-climate-consequences/)
Hydrogen oxidation may also impact tropospheric ozone and stratospheric water vapour concentrations, which can also result in net warming (Ocko, I.B. and S.P. Hamburg (2022). “Climate consequences of hydrogen emissions”, European Geosciences Union, see: https://doi.org/10.5194/acp-22-9349-2022)

6. For example, hydrogen distribution (especially for FCEV distributed stations) requires new infrastructure (specialized pipelines, specialized transport trucks, specialized refuelling stations). e.g., Kurtz, J.M., Sprik, S., and T.H. Bradley (2019), “Review of transportation hydrogen infrastructure performance and reliability”, OSTI, see: https://www.osti.gov/servlets/purl/1506613

Slide 46 footnotes

1. Calculated in other studies by applying hydrogen as a fuel carrier, divided by the total fuel use.

2. In their study, the Transition Accelerator projected a scenario where hydrogen could be an energy carrier for approximately 27% of Canada's primary energy demand in 2050. They further examine the potential for a hydrogen export market in the United States that could replace the bulk of the market share of current carbon-based fuel exports. The study authors also consider feedstock applications as part of their estimates. From: Layzell, D. *et al*. (2020) Towards Net-Zero Energy Systems In Canada: A Key Role For Hydrogen, see: https://transitionaccelerator.ca/wp-content/uploads/2020/09/Net-zero-energy-systems_role-for-hydrogen_200909-Final-print-1.pdf

3. This strategy suggests that hydrogen could represent 6% of delivered energy and 45 $MtCO_2e$ of GHG savings by 2030, and 30% of delivered energy and 190 $MtCO_2e$ GHG savings by 2050.

4. Values are either reported in PJ or have been converted to PJ from reported "Mt of H_2", using the low heat value (LHV) of Hydrogen (113 MJ/kg). 1 Mt = 113 PJ LHV Hydrogen. The Transition Accelerator reports PJ of H_2 for the high heat value of Hydrogen (141 PJ / Mt). This was converted to the LHV. Exports were subtracted and only domestic use is reported for the CER Energy Dashboard.

Slide 47 footnotes

1. The Auditor General's review of the Federal Hydrogen Strategy found that at 45 $MtCO_2$ of abatement, the Strategy's 2030 estimates are overly optimistic, and noted that in contrast, Canada's environment ministry estimated hydrogen technology would cut 15 $MtCO_2$ of emissions by 2030. (Williams, N. (2022). "Canada overestimating hydrogen's potential to cut carbon emissions, reports says", Reuters, see: https://www.reuters.com/world/americas/canada-overestimating-hydrogens-potential-cut-carbon-emissions-report-says-2022-04-26/)

2. In 2030, we see 25+ $MtCO_2$ abatement in 2030 provincial strategies (n/a for Ontario), *vs.* 45 $MtCO_2$ anticipated by the federal strategy.

3. 2030 goals + Ontario's 2050 goal.

4. Ports are high-emission point sources of both GHGs and local air pollutants. Activity is heavily reliant on diesel and applications share common fuelling infrastructure. Further, ports reflect a "return to base" operation and are under federal jurisdiction.

5. Such as for replacing fuel in heavy equipment. (First Mode (2023), "World's largest fuel cell electric vehicle completes successful year of trials", see: https://firstmode.com/updates/worlds-largest-fcev-vehicle-completes-trials/)

6. Source: Natural Resources Canada (2020). "Hydrogen Strategy for Canada", see: https://natural-resources.canada.ca/sites/nrcan/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

7. Under construction, proposed to launch by 2024. (Government of Alberta (2023). "Air products hydrogen production and liquifaction facility", see: https://majorprojects.alberta.ca/details/Air-Products-Hydrogen-Production-and-Liquefaction-Facility/4461)

8. Bruce County (2020). "Bruce Innovates", see: https://www.brucecounty.on.ca/sites/default/files/file-upload/bruce_innovates_-_foundational_hydrogen_infrastructure_project_-_overview_-_2020.pdf

Slide 48 footnotes

1. Government of British Columbia (2021), "B.C. hydrogen strategy", see: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bc_hydrogen_strategy_final.pdf
2. Government of Alberta (2021). "Alberta hydrogen roadmap", see: https://www.alberta.ca/hydrogen-roadmap
3. Government of Saskatchewan (2022), "Saskatchewan is going blue", see: https://www.saskatchewan.ca/government/news-and-media/2022/may/16/saskatchewan-is-going-blue
4. Government of Manitoba, "Manitoba Environment and Climate Change", see: https://www.gov.mb.ca/sd/environment_and_biodiversity/energy/hydrogen/committee.html
5. Government of Ontario (2022). "Ontario's low-carbon hydrogen strategy", see: https://www.ontario.ca/page/ontarios-low-carbon-hydrogen-strategy
6. Governmetn of Quebec (2022). "Quebec green hydrogen and bioenergy strategy", see: https://www.quebec.ca/en/government/policies-orientations/strategy-green-hydrogen-bioenergy#:~:text=In%202030%2C%20green%20hydrogen%20and,gasoline%20vehicles%20from%20the%20roads.https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bc_hydrogen_strategy_final.pdf
7. Government of Newfoundland and Labrador (2022). "Maximize our renewable future", see: https://www.gov.nl.ca/iet/files/Renewable-Energy-Plan-Final.pdf
8. Port Belledune, New Brunswick (2023). "Canada's green energy hub", see: https://portbelledune.ca/green-energy-hub/green-hydrogen-project/
9. Prince Edward Island - see CBC News (2023). "P.E.I. company investing millions in green energy", see: https://www.cbc.ca/news/canada/prince-edward-island/pei-aspin-kemp-green-hydrogen-1.6704791
10. Natural Resources Canada (2020). "Hydrogen Strategy for Canada", see: https://natural-resources.canada.ca/sites/nrcan/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf
11. Yukon - Navius Research for Government of Yukon Department of Energy, Mines and Resources (2022). "Potential of hydrogen to help decarbonize the Yukon", see: https://yukon.ca/sites/yukon.ca/files/emr/emr-potential-hydrogen-help-decarbonize-yukon.pdf

Slide 49 footnotes

1. Unlike RNG, which is readily substitutable for natural gas and can therefore take advantage of existing natural gas infrastructure, hydrogen's properties create numerous challenges for repurposing existing pipelines and equipment (e.g. embrittlement of steel causing leakage and equipment malfunction). Work is ongoing to develop safe and economical ways to transport and use hydrogen (Topolski, K. et al. (2022). "Hydrogen blending into natural gas pipeline infrastructure: review of the state of technology", National Renewable Energy Laboratory, see: https://www.nrel.gov/docs/fy23osti/81704.pdf)

2. Meaning that hydrogen distribution costs within a province do not vary depending on where within the province hydrogen is transported.

3. Such as for indoor/underground vehicles that do not produce CO_2e missions in confined spaces.

4. Natural Resources Canada (2020). "Hydrogen Strategy for Canada", see: https://natural-resources.canada.ca/sites/nrcan/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

5. The federal and some provincial (B.C., Alberta and Maritimes) hydrogen strategies recognize the potential of American, Asian and European Hydrogen markets in a net-zero focused future economy. Oil-producing provinces have partly assessed the conversion of fossil natural gas into hydrogen as a clean export fuel. e.g. Government of Alberta (2021). "Alberta hydrogen roadmap", see: https://www.alberta.ca/hydrogen-roadmap

6. ""IRA's 45V tax credit is the most generous clean hydrogen subsidy in the world." Per Jesse Jenkins, see: https://www.cnbc.com/2023/10/13/why-ira-hydrogen-tax-credit-is-lightning-rod-for-controversy.html

7. The Transition Accelerator (2023). "Net Zero Fuels", see: https://transitionaccelerator.ca/focus-area/net-zero-fuels/

8. Khan, M.A. et al. (2023). "Hydrogen and the decarbonization of steel production in Canada", The Transition Accelerator, see: https://transitionaccelerator.ca/reports/hydrogen-and-the-decarbonization-of-steel-production-in-canada/

9. As noted previously, hydrogen gas reacts readily in the atmosphere with the same molecule responsible for breaking down methane, which is a potent greenhouse gas. Researchers have posited that if the level of hydrogen emissions surpasses a specific threshold, this shared reaction is likely to result in an accumulation of methane in the atmosphere.

10. Safety is another aspect of the hydrogen economy that is widely under research. Salehi et al. (2022). "Overview of safety practices in sustainable hydrogen economy - an Australia perspective", International Journal of Hydrogen Energy, see: https://doi.org/10.1016/j.ijhydene.2022.08.041

Slide 51 footnotes

1. Such as the *Technology Innovation and Emissions Reduction (TIER) Regulation* in Alberta. On January 1, 2023, Alberta made material amendments to its carbon credit system under TIER Regulation in an attempt to provide more certainty for proponents of geological CCUS projects. The amendments include creating two new types of carbon credits – a “sequestration credit” and a “capture recognition tonne.” (Government of Alberta (2023). “Technology Innovation and Emissions Reduction Regulation”, see: https://www.alberta.ca/technology-innovation-and-emissions-reduction-regulation)

2. Offshore storage exploration of Maritime offshore basin is underway. Solid Carbon has an in-situ mineralization demonstration on the west-coast. These explorations are not captured in our model results (Haydu, C. (2023). “Opportunities galore: recent call for bids offer lots of potential for Nova Scotia offshore”, Daily Oil Bulletin, see:https://www.dailyoilbulletin.com/article/2023/1/30/opportunities-galore-recent-call-for-bids-offer-lo/; Solid Carbon (2023), “a rock-solid climate solution”, see: https://solidcarbon.ca/#theplan)

3. In Quebec, the venture Deep Sky is exploring a partnership with Svante to characterize the subsurface basin. Businesswire (2023), “Carbon removal leaders Deep Sky and Svante partner to study carbon storage feasibility in southern Quebec, Canada”, see: https://www.businesswire.com/news/home/20230817708842/en/Carbon-Removal-Leaders-Deep-Sky-and-Svante-Partner-to-Study-Carbon-Storage-Feasibility-in-Southern-Quebec-Canada

Slide 52 footnotes

1. Capture technologies fall into two categories: pre-combustion and post-combustion. Post-combustion technologies are applied in boilers, cement kilns and industrial burners to separate up to 90% (or potentially more) of CO_2 from flue gases from fossil fuel burning. Pre-combustion technologies separate out CO_2 as part of a chemical process before combustion. For example, production of hydrogen through steam methane reforming involves processing methane under high temperature and pressure, forming hydrogen and carbon monoxide, which is later converted to CO_2.

2. CO_2 can be stored in deep geologic formation (generally >2 km deep) such as deep saline aquifers.

3. In the EOR process, CO_2 is injected into depleted oil reservoirs to increase pressure, thereby forcing more hydrocarbons out of rock. In Canada, the majority of sequestered carbon is used for EOR (~3.6 Mt/year), with the majority going into the Weyburn field in Saskatchewan or Clive field as part of the Alberta Carbon Trunk Line. The remainder (~1.2 Mt/year), is stored through saline aquifer storage projects Quest and Aquistore. (Hares, R., McCoy, S., and D.B. Layzell (2022), "Review of carbon-dioxide storage potential in western Canada: blue hydrogen roadmap to 2050", The Transition Accelerator, see: https://transitionaccelerator.ca/wp-content/uploads/2023/05/TA-Report-4.6_Review-of-Carbon-Dioxide-Storage-Potential-in-Western-Canada_V1-1.pdf)

4. Fertilizer production is another potential commercial demand centre for captured CO_2 but is not currently explored in our modeling. (Fertilizer Canada (2023). "Impact of the emerging hydrogen economy on the fertilizer industry", see: https://fertilizercanada.ca/wp-content/uploads/2023/08/Hydrogen-Economy-and-the-Fertilizer-Industry_March-1.pdf)

5. Global CCS Institute (2021). "The costs of CO_2 storage", see: https://www.globalccsinstitute.com/archive/hub/publications/119816/costs-co2-storage-post-demonstration-ccs-eu.pdf. Section 4 and 5. A sensitivity analysis on the cost of new wells + monitoring, which range from an additional 3-14 Euros of expense/tonne of CO_2 sequestered.

6. Sum of first and second competition selected proposals. Government of Alberta (2023). "Carbon capture, utilization and storage - carbon sequestration tenure", see: https://www.alberta.ca/carbon-capture-utilization-and-storage-carbon-sequestration-tenure

Slide 53 footnotes

1. Currently there are about 4 Mt of installed CCUS in Canada, split between Saskatchewan and Alberta (captured and injected). These are reflected by the numbered sites shown on the figure (#1 - #8).

2. The Canadian Carbon Management strategy states an expected goal of 16.3 MT of CCUS implemented by 2030. By 2050, the report cites NRCAN's CER target between 46 and 80 MT. The strategy also supports the development of carbon sequestration hubs for industrial clusters, noting storage locations in Alberta, Saskatchewan and some of British Columbia. The report also supports potential development for Ontario, Quebec and offshore maritimes basins (which are not seen here). The report indicates transportation as a large hurdle for the effective implementation of these hubs. (Government of Canada (2023). “Canada's carbon management strategy”, see: https://natural-resources.canada.ca/climate-change/canadas-green-future/capturing-the-opportunity-carbon-management-strategy-for-canada/canadas-carbon-management-strategy/25337)

3. Alberta has a pore space tenure framework which is distinct from mineral rights and allow specific areas of the subsurface to be leased for evaluation and sequestration. This framework subdivides underground storage into many different aquifers, which can be characterized and regulated whilst managing overlapping interest. (Government of Alberta (2023) “Small-scale and remote carbon sequestration tenure - application guidelines”, see: https://training.energy.gov.ab.ca/Guides/Small-Scale%20and%20Remote%20Carbon%20Sequestration%20Tenure%20-%20Application%20Guidelines.pdf)

4. In 2020, at least 12 CCUS hubs were were in development globally, including in Australia, Europe and the United States. (International Energy Agency (2020). “Energy Technology Perspectives”, see: https://iea.blob.core.windows.net/assets/181b48b4-323f-454d-96fb-0bb1889d96a9/CCUS_in_clean_energy_transitions.pdf)

5. The Pathways Alliance is a group of six oil sands companies with net-zero initiatives.

6. Natural gas and coal-fired plants developed with capture in mind are similarly priced to the cost to retrofit existing plants. (Schmitt, T. and S. Homsy (2023). “Cost and performance of retrofitting NGCC units for carbon capture - Revision 3”, see: https://www.osti.gov/servlets/purl/1961845)

Slide 54 footnotes

1. Alberta has directives for exploring carbon capture and has policy on developing CCUS. Alberta also has a carbon offset crediting program as part of its TIER industrial carbon pricing system. There are plans to capture ~40 Mt by 2035 from about 20–30 operators, whose business plans revolve around selling carbon credits. (Government of Alberta (2023). “Carbon capture, utilization and storage - carbon sequestration tenure”, see: https://www.alberta.ca/carbon-capture-utilization-and-storage-carbon-sequestration-tenure)

2. As of 2021, Saskatchewan has a plan to continue developing CO_2 pipelines, explore hub models and increase CO_2 EOR royalties. (Government of Saskatchewan (2021). “Saskatchewan announces carbon capture utilization and storage priorities”, see: https://www.saskatchewan.ca/government/news-and-media/2021/september/07/saskatchewan-announces-carbon-capture-utilization-and-storage-priorities)

3. Quebec does not have geologic carbon capture in their policy platform. There is activity underway to develop the basin by Deep Sky partnered with Svante for storage. (Osler (2021). “Carbon and greenhouse gas legislation in Quebec”, see: https://www.osler.com/en/resources/regulations/2021/carbon-ghg/carbon-and-greenhouse-gas-legislation-in-quebec ; Businesswire (2023), “Carbon removal leaders Deep Sky and Svante partner to study carbon storage feasibility in southern Quebec, Canada”, see: https://www.businesswire.com/news/home/20230817708842/en/Carbon-Removal-Leaders-Deep-Sky-and-Svante-Partner-to-Study-Carbon-Storage-Feasibility-in-Southern-Quebec-Canada)

4. Ontario is building a roadmap for development of CCUS with an update expected in fall 2023. There are no plans to consider implementation until 2025. (Government of Ontario (2023). “Geologic carbon storage”, see: https://www.ontario.ca/page/geologic-carbon-storage)

5. a) Northwestern BC basin shape and deep saline aquifer prospective capacity estimate: Rakhit, K. and N. Sweet (2022). “Northwest BC geological carbon capture and storage atlas”, see: https://www.geosciencebc.com/projects/2022-001/)
b) Quebec basin shape and prospective capacity estimate: Bedard, K., Malo, M. and F.-A. Comeau (2013). “CO_2 geological storage in the province of Québec, Canada capacity evaluation of the St.Lawrence Lowlands basin”, Energy Procedia, see: https://doi.org/10.1016/j.egypro.2013.06.422)
c) Ontario basin shape and prospective capacity estimate: Capacity Evaluation of the St. Lawrence Lowlands basin: Shafeen, A. et al. (2004). “CO_2 sequestration in Ontario, Canada. Part I: storage evaluation of potential reservoirs”, Energy Conversion and Management, see: https://doi.org/10.1016/j.enconman.2003.12.003)
d) Albertan saline aquifer shapes from the NatCarb V6 carbon sequestration atlas. (National Energy Technology Laboratory (2023),see: https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/natcarb-atlas). Herein, a specific formation (Cambrian Basal Sands) and associated contingent capacity estimate is used for (AB,SK, MB and parts of the US): Peck, W.D. et al. (2014). “Storage Capacity and Regional Implications for Large-Scale Storage in the Basal Cambrian System.” PCOR Phase III, Task 16 Deliverable D92, Plains CO_2 reduction (PCOR) Partnership, see: https://www.osti.gov/servlets/purl/1874349

Slide 55 footnotes

1. The main industries which demonstrate persistent natural gas and natural gas liquids usage are in the Heavy Industry as well as the Light Manufacturing sectors. RNG is also used in combination with fossil natural gas in these (and other) sectors.

2. CCUS in electricity generation in our gTech net-zero results is typically paired with RNG, resulting in net-negative emissions *via* BECCS (especially in high-RNG pathways like High Renewables). Other forms of electricity generation such as solar, wind, hydro, and nuclear, are not included in this instance because CCUS does not apply to these electricity generation technologies.

3. By 2050, 6-10% of sequestered CO_2 is used for EOR across NZ pathways except in the High Renewables pathway, which phases out EOR by 2050. Non-storage utilization is not broadly considered in the model because it is not permanent, though in practice CO_2 is used also for urea (fertilizer) manufacturing.

4. Note this figure is based on gTech results, which typically show less renewables and more RNG, whereas IESD shows less CCUS use in electricity generation.

Slide 56 footnotes

1. These reports have separate categories for direct air capture, so we expect that the values reported here are strictly for CCUS.

2. The Hydrogen pathway (not shown in the figure), has a similar CCUS projection as the Bioenergy pathway (203 Mt of CO_2 captured in 2050).

3. Note that in our Renewables pathway, fossil fuel production is phased out by 95% in 2050, although natural gas persists in Heavy Industry, Light manufacturing, and to a minor degree in other sectors such as Transportation and Buildings.

4. The operation of CCUS facilities is also energy intensive, which contributes to the persistent use of fossil-based energy.

Slide 57 footnotes

1. A recent study showed that about 70% of emissions in China, Europe, and the United States are within 100 km of potential storage, highlighting the importance of infrastructure development (International Energy Agency (2020). “Energy technology perspectives”. see: https://iea.blob.core.windows.net/assets/181b48b4-323f-454d-96fb-0bb1889d96a9/CCUS_in_clean_energy_transitions.pdf)

2. Formations within the Western Canadian Sedimentary Basin (WCSB) stretching across northwestern British Columbia, Alberta, and Saskatchewan, have undergone extensive exploration since the 1950’s (primarily for hydrocarbons) and are well understood compared to the basins in Ontario and Quebec. More recently, parts of the WCSB have also been evaluated for CO_2 storage (see Slide 58). Notably the basins in Canada have overlapping pore space with the U.S., which has implications for regulations and/or competition for future sequestration projects, especially in lower capacity basins in Ontario and Quebec.

3. This 50 km figure closely matches a cutoff for smaller-scale distribution networks (smaller pipelines, less requirements than a trunk line). (U.S. Department of Energy (2015). “A review of the CO_2 pipeline infrastructure in the U.S.”, see: https://www.energy.gov/policy/articles/review-co2-pipeline-infrastructure-us).This is also a relatively short distance for truck transport to sites, as truck transport costs increase linearly over distance.

4. These areas are leased by different operators, primarily for the purpose of evaluating the area for the establishment of potential storage hubs. Being relatively far along in the development process, they are categorized as “proposed infrastructure” in our analysis.

Slide 58 footnotes

Refer to Slide 54 for map citations, Footnote 5.

1. Emissions are based on large final emitter point-sources from Environmental and Climate Change Canada (2021). There is a cutoff to only show the largest emitters, defined as having emissions above 0.2 Mt/year CO_2 (Environment and Climate Change Canada (2021) “Canada’s official greenhouse gas inventory - Main page”, see: https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/inventory.html)

2. We note that transportation of CO_2 also plays an important role in infrastructure planning. This work has been approached in the NRCan CCUS assessment framework, which links emitters and possible transport networks to storage. Hughes, R. (2022). “National CCUS Assessment Framework”, Natural Resources Canada, see: https://engineering.ubc.ca/sites/default/files/2022-04/NRCan_National_CCUS_Modelling_Framework.pdf

Slide 59 footnotes

1. In key sectors where CCUS can be readily implemented (e.g., chemical manufacturing, cement production, electricity generation, and oil sands). Emissions are based on large final emitter point-sources from Environment and Climate Change Canada. There is a cutoff to only show the largest emitters, defined as having emissions above 0.2 Mt CO_2/year (Environment and Climate Change Canada (2021) “Canada’s official greenhouse gas inventory - Main page”, see: https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/inventory.html)

2. These criteria are described on Slide 57. We excerpt the layers with best access to storage and infrastructure for visualization purposes here.

3. The sum of emissions from these infrastructure categories in Alberta is 115 Mt. The theoretical capture capacity of plant is 90%.Theoretical capture is the total capturable emissions multiplied by the theoretical capacity (115 Mt x 90% = 104 Mt)

4. The sum of emissions from these geology categories in Ontario is 19 Mt. The theoretical capture capacity of plant is 90%.Theoretical capture is the total capturable emissions multiplied by the theoretical capacity (19 Mt x 90% = 17 Mt).

5. Unique geology in different provinces can also impose geographic constraints, especially in regions where prospective capacity for storage is limited compared to other regions.

Slide 60 footnotes

1. Burning/converting fossil natural gas generates a flue/exhaust stream containing CO_2 that can be captured. Some chemical plants can produce flue streams that are nearly 99% pure CO_2, such as in ammonia manufacture. Carbon capture associated with SMR hydrogen manufacture typically captures 60% of total CO_2 emissions (from the process stream, not necessarily from the flue gas). Autothermal reformation concentrates all emissions into a process stream and can inherently capture 95% of CO_2 emissions. (Gorski, J., Jutt T. and K. Tam Wu (2021). “Carbon intensity of blue hydrogen production”, Pembina Institute, see: https://www.pembina.org/reports/carbon-intensity-of-blue-hydrogen-revised.pdf)

The amount of CO_2 captured from cement and steel production is higher when the CO_2 generated as a byproduct of chemical reactions in these manufacturing processes is also captured, in addition to the CO_2 in flue gases from natural gas boilers. (International Energy Agency (2020). “Energy technology perspectives 2020”, see: https://iea.blob.core.windows.net/assets/181b48b4-323f-454d-96fb-0bb1889d96a9/CCUS_in_clean_energy_transitions.pdf)

2. Infill drilling (new wells between existing wells) and waterflood (injecting water to increase pressure) are cheaper forms of oil recovery than EOR (Energy Glossary (2023), “infill drilling”, see: https://glossary.slb.com/en/terms/i/infill_drilling; Energy Glossary (2023), “waterflood”, see: https://glossary.slb.com/en/terms/w/waterflood)

3. For example, in Alberta long-term liability is not transferred to the province after the CO_2 EOR production lease expires. This differs from permanent sequestration leases, where long-term liability is transferred to the province. (Bankes, N. (2019). “Alberta’s approach to the transfer of liability for carbon capture and storage projects”, International Journal of Risk Assessment and Management, see: https://cdrlaw.org/wp-content/uploads/2020/09/ijram.2019.103331.pdf)

4. Urea can be manufactured using CO_2 as a feedstock. Globally, urea production is the most common use for CO_2, with over 130 Mt produced annually, mainly for fertilizers. Urea breaks down into ammonia and CO_2, which is released back into the atmosphere. (International Energy Agency (2023). “CO_2 capture and utilisation”, see: https://www.iea.org/energy-system/carbon-capture-utilisation-and-storage/co2-capture-and-utilisation)

5. See Zhang et al. (2020). “Recent advances in carbon dioxide utilization”, Renewable and Sustainable Energy Reviews, see: https://doi.org/10.1016/j.rser.2020.109799

6. Carbon Cure Press Release (2022), “Concrete as a carbon removal pathway”, see: https://go.carboncure.com/rs/328-NGP-286/images/CarbonCure-Brochure-Concrete-101.pdf

Slide 62 footnotes

1. DAC was not limited in our pathways, however its cost was set 'high' in all pathways except for Fossil with CCUS and in our reference pathways. Our modelling assumes an optimistic levelized starting cost for DAC in both of our reference scenarios and for our Fossil with CCUS pathway, which is in line with current cost estimates for this nascent technology. We apply a "reference" (middle of the road) cost for DAC, where the levelized cost of capture in a DAC plant starts at \$734/tCO_2e (pre-commercialization abatement cost) and declines with experience to a potential price floor of \$164/tCO_2e (\$354/tCO_2e for 1 Mt capture). The high-cost sensitivity represents the highest value reported in the literature (\$501/tonne). See Figure 3 in Navius Research (2023). "Net zero Canada methodology report", see: https://www.naviusresearch.com/wp-content/uploads/2023/06/Methodology-Report-for-First-Clean-Prosperity-Paper-2023-06-16.pdf

2. The DAC technology modelled is estimated to be at Technology Readiness Level (TRL) 6. TRL 6-8 include pilot tests and successful full-scale prototypes in operational environments. See: Intergovernmental Panel on Climate Change (2022). "Climate Change 2022: Mitigation of Climate Change", see:https://www.ipcc.ch/report/ar6/wg3/).

3. Liquid DAC is a type of direct air capture where atmospheric air is pulled into a filter system via a fan array. The filter system is comprised of high-pH solvents which react with air to form a CO_2-rich solution with CO_2 captured as an aqueous carbonate salt. CO_2 salts are precipitated out of solution as pellets, which are then reused in the cycle and heated to high temperatures (between 300-900 C) in order to release pure CO_2 for capture. This system is often coupled with underground storage. This type of storage is typified by the Carbon Engineering DAC plants (Carbon Engineering (2023), see: https://carbonengineering.com/our-technology/)

4. CO_2 transfer to storage geology could occur through pipelines but would be an added expense for DAC plant implementation.

5. To realize the deployment and storage projections anticipated by the model, DAC development would benefit from expanded regulatory support (e.g., eligibility for carbon offset programs). The federal offset program does not currently include direct air capture with CCUS as an eligible offset. Environment and Climate Change Canada is revising the framework to include DAC systems (Government of Canada (2023), "Canada's greenhouse gas offset credit system: protocols", see: https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system/federal-greenhouse-gas-offset-system/protocols.html).
Alberta, B.C and Quebec have their own carbon offset systems. Alberta and B.C have protocols for carbon sequestration from regulated facilities. Quebec does not support engineered CDR.
British Columbia: Government of British Columbia (2023). "Offset protocols", see: https://www2.gov.bc.ca/gov/content/environment/climate-change/industry/offset-projects/offset-protocols
Alberta: Government of Alberta (2023). "Alberta emission offset system", see: https://www.alberta.ca/alberta-emission-offset-system
Quebec: Government of Quebec (2023), "Carbon market offset credits", see: https://www.environnement.gouv.qc.ca/changements/carbone/credits-compensatoires/index-en.htm

6. Currently 1-7 tonnes of water, in some cases as high as 13 tonnes, are used to capture 1 tonne of CO_2 using liquid DAC technology. As discussed in later slides, DAC also requires substantial heat and electric energy to operate, as reflected in our model results on Slide 65. (See Ozkan et al. (2022). "Current status and pillars of direct air capture technologies", iScience, see: https://doi.org/10.1016/j.isci.2022.103990)

7. Solid DAC is a direct air capture process where atmospheric air is pulled into a filter system via a fan array. The filter system is comprised of membranes coated with solid sorbents which capture and filter CO_2. The filters are then heated to ~100 C and the CO_2 evaporates off the sorbent for collection and capture. This type of storage is typified by Climeworks DAC plants, as noted on Slide 64.

8. Carbon Removal Canada has recently estimated that Canada will need 300 Mt per year of CDR just to offset historical emissions (at the lowest end of the scale to remain within 1.5C of warming). This suggests the long-term use of resources for CDR deployment will likely be required to address historical emissions, rather than for for the continued offset of residual emissions. T. Bushman and N. Merchant (2023) Ready for Removal: A Decisive Decade for Canadian Leadership in Carbon Dioxide Removal See: https://carbonremoval.ca/wp-content/uploads/2023/11/CRC_ResearchReport_ReadyForRemoval.pdf

9. Ocean alkalinity modification entails spreading fine-ground alkaline minerals into the ocean to neutralize ocean acidity and sequester CO_2 as bicarbonate ions or artificially electrolysing ocean water into basic solutions.

Slide 63 footnotes

1. The reference cost for a first-of-a-kind plant is $354/t$CO_2$ whilst the nth-of-a-kind plant lowers this price to $164/t$CO_2$. High costs are one of the reasons why DAC appears much later in the model. DAC input costs employed are further detailed on Appendix Slide 80.

2. “According to the Intergovernmental Panel on Climate Change, DAC and other negative emissions technologies will need to sequester some 1 billion tonnes (or 1 gigatonne, Gt) of CO_2 every year by 2030 to keep planetary warming below 1.5 °C above pre-industrial levels. By 2050, the annual figure could reach as high as 20 Gt”. (Service, R.F. (2023). “U.S. unveils plans for large facilities to capture carbon directly from air”, Science, see: https://www.science.org/content/article/us-unveils-plans-for-large-facilities-to-capture-carbon-directly-from-air)

Slide 64 footnotes

1. The information shown is adapted and revised from Fong, C. and S. MacDougall (2023). "Engineered carbon dioxide removal in a net-zero Canada". Pembina Institute, see Table 1: https://www.pembina.org/pub/engineered-carbon-dioxide-removal-net-zero-canada

2. We note the chart represents a non-exhaustive list and does not include biologic CDR technologies such as biochar, bio-oils, etc.

3. Storage is included here as DAC is constrained in this way in the model.

Slide 65 footnotes

1. Fossil fuels also remain in the Bioenergy, Renewables, and Hydrogen pathways, resulting in a similar requirement for negative emissions. Because in these pathways the cost for biofuels is set to be lower than in Electrification, negative emissions are primarily achieved through BECCS, thus lowering the requirement for DAC.

2. Given the current stage of DAC development, this level of DAC deployment is improbable by 2040 without monumental advances in the technology as well as vast investment in and commercialization of DAC in the near future.

3. Only liquid DAC (L-DAC) plants are currently modelled in gTech. The L-DAC process typically requires electricity as well as significant amounts of high heat to process. However, other DAC options (including solid DAC, which does not typically require high temperature heat) may become more technologically and economically viable, which would change the energy consumption profile. (Ozkan et al. (2022). “Current status and pillars of direct air capture technologies”, iScience, see: https://doi.org/10.1016/j.isci.2022.103990)

Slide 66 footnotes

1. Many of the studies looking at engineered DAC are also using Navius' gTech model.

2. All the studies in the upper set of results are based on gTech.

3. The CCI dashboard uses wildcard values, so these results are not part of a scenario but sum the maximum (or minimum) CCUS and DAC values.

Slide 67 footnotes

1. The model chooses Alberta for DAC in part due to marginal cost differences in the model that make DAC more economical to adopt in Alberta over other areas with storage potential (like Saskatchewan). Northwestern B.C., Alberta, and Saskatchewan have well-studied underground storage and are in various stages of developing new CCUS. Future developments into “open-hub” injection are compatible with DAC capture. These basins are theoretically large enough to accommodate DAC model results for all five modelled pathways including the Fossil with CCUS pathway.

2. Such as the Investment Tax Credit for Carbon Capture, Utilization and Storage, which is available to DAC operators that inject CO_2 into permanent storage (but not applicable when captured CO_2 is injected for EOR).

Slide 68 footnotes

1. For an L-DAC system, capturing one tonne of CO_2 can require between 1 and 7 tonnes of water across possible sites in North America. (World Resources Institute (2021). “Direct Air Capture: resource considerations and costs for carbon removal”, see: https://impakter.com/direct-air-capture-resource-considerations-and-costs-for-carbon-removal)

2. Adapted from Lebling, K. et al. (2022). “Direct Air Capture: assessing impacts to enable responsible scaling.” Working Paper. World Resources Institute, see: https://doi.org/10.46830/wriwp.21.00058.

3. McQeen, N. et al. (2021) “Natural Gas vs. Electricity for Solvent-Based Direct Air Capture“ Frontiers in Climate, see: https://www.frontiersin.org/articles/10.3389/fclim.2020.618644/full

4. The DAC Atlas incorporates storage availability, low carbon heat, natural gas/electricity availability, and atmospheric conditions to determine optimized spots to implement DAC in the U.S. Great Plains Institute (2023). “An Atlas of Direct Air Capture”, see: https://betterenergy.org/blog/new-atlas-identifies-top-us-regions-for-direct-air-capture-deployment/).

5. DAC coupled with long-term storage generally does not produce a marketable product. However, applications are possible for EOR and for creating synthetic fuels.

6. Pore space must be regulated at a formation-scale in the subsurface. These rights differ from surficial mineral rights and allow operators to access the storage resource within clear regulatory and legal guidelines. This framework is available in Alberta, while other provinces have less complete regulatory frameworks (Alberta Energy Regulator (2023). “Carbon capture, utilization, and storage”, see: https://www.aer.ca/providing-information/by-topic/carbon-capture)

7. It is hard to quantify the carbon removal from technologies such as direct mineralization. Developing protocols to verify the sequestration of CO_2 makes these technologies more viable.

Slide 69 footnotes

1. Canada is estimated to need 300 Mt per year of CDR just to offset historical emissions at the lowest end of the scale to remain within 1.5C of warming. T. Bushman and N. Merchant (2023) Ready for Removal: A Decisive Decade for Canadian Leadership in Carbon Dioxide Removal See: https://carbonremoval.ca/wp-content/uploads/2023/11/CRC_ResearchReport_ReadyForRemoval.pdf

2. High risks associated with pathways that depend heavily on carbon removal have been flagged internationally, particularly in cases where carbon removal is relied upon to offset inadequate near-term emissions cuts. (Stuart-Smith, R.F. et al. (2023). “Legal limits to the use of CO_2 removal”, Science, see: 10.1126/science.adi933).
Generally, risk analysis is an important consideration for future work. Modelling results currently represent the possible technological pathways without incorporating a risk dimension.

3. At a given point in time, the model has no way of anticipating that more climate action (such as a planned increase in carbon pricing) will happen in the future. The decisions for technology deployment are therefore made based only on the conditions at that point in time. In reality however, decisions are made with consideration of the future. When there is high likelihood of continued strengthening of net-zero initiatives, a decision in favour of carbon lock-in is not likely to be made due to anticipation of higher costs in the future, even if that decision seems initially economically optimal at the time. Similarly, if “foresight” was incorporated into the model, the model would likely choose a less emissions-intensive path in order to lower costs in the long run.

4. International Energy Agency (2023). “International Energy Outlook”, see: https://www.iea.org/news/the-energy-world-is-set-to-change-significantly-by-2030-based-on-today-s-policy-settings-alone

5. Described in a two-part discussion by the Canadian Climate Institute (2023), “Locking out carbon lock-in”, see: https://climateinstitute.ca/locking-out-carbon-lock-in-part-1/#:~:text=At%20first%20glance%2C%20carbon%20lock,years%20or%20decades%20to%20come

Slide 71 footnotes

1. With the exception of work by the Institut de l'énergie Trottier, which examined the delta between electricity projections by planners in Central and Eastern Canada compared to reference and net-zero estimates by the Canadian Energy Outlook (Table 4). See: Edom, E., Langlois-Bertrand, S., Mousseau, N. (2022). A Strategic Perspective on Electricity in Central and Eastern Canada, Institut de l'énergie Trottier, Polytechnique Montréal.

Slide 73 footnotes

1. Key examples include the absence of the option for district heating (which requires substantive changes in the way energy is produced and distributed) and moving away from personal vehicles. Linking to a spatial model would be required to simulate preferences for transport options and systematically addressing the way we travel.

2. The lack of a spatial dimension in the models is a key limitation. For example, IESD accounts for some aspects of required grid updates, but represents incremental costs associated with increasing peak demand via a uniform provincial average distribution and transmission cost. Using a spatially explicit model may result in cost estimates that are either higher or lower than what is contained in IESD.

3. For example, see McKinsey & Co (2023). "Renewable-energy development in a net-zero world: Disrupted supply chains", see: https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/renewable-energy-development-in-a-net-zero-world-disrupted-supply-chains

4. Such as roles and mandates of provincial electricity regulators.

5. 2023 has been a record-breaking year for wildfires in Canada, with an estimated 1,420 Mt of GHG emissions released so far, which is more than double of all other sectoral emissions combined. (Source: Natural Resources Canada 2023 estimate as of July, National Inventory Report 2023. See: Bochove, D. (2023). "Wildfires are set to double Canada's climate emissions this year", see: https://www.bloomberg.com/news/features/2023-07-26/massive-carbon-emissions-of-canada-wildfires-are-off-the-scale)

Slide 74 footnotes

1. Models are built and maintained by Navius Research Inc. (www.naviusresearch.com)

2. In our version of the model, gTech and IESD are partly coupled. Lack of full model integration has some implications for results, particularly where there may be differences in the electricity generation mix between the two models. However, the overall trends in the energy economy remain consistent. Figure has been adapted from Navius Research 2023. A description of the fully coupled version of the model can be found here: https://canadaenergydashboard.com/data/navius_research_gtech_iesd_model_documentation.pdf

3. IESD simulates the electricity system for each consecutive hour of the year which allows examining the potential for technologies such as renewables combined with energy storage. While the model requires sufficient capacity to meet demand in every hour of the year and also requires a certain amount of back-up capacity, it does not run on a second-by-second level like some utility models do. The model does therefore not account for all resource adequacy requirements linked to transitioning the grid to net zero. IESD also does not have the spatial detail to represent intra-provincial transmission planning in detail. A more detailed exploration of the internal dynamics of energy management (e.g., meeting peak demand or optimizing the deployment of storage) would require a different model that works at finer spatial and temporal scales, such as models used by utility operators for planning purposes. (See Rhotes, E. et al. (2021). "How do energy-economy models compare? A survey of model developers and users in Canada", Sustainability, see: https://doi.org/10.3390/su13115789; Arjmand, R. and M. McPherson (2022). "Canada's electricity system transition under alternative policy scenarios", Energy Policy, see: https://doi.org/10.1016/j.enpol.2022.112844)

4. Costs can change in future years within the model depending on the demand for RNG.

5. For example, the absence of feedstock transport costs is a key limitation due to the generally low bulk density and high water content of RNG feedstocks, which can render transport costs quite high. The model accounts for feedstock transportation costs but does not vary intra-provincial transportation costs (i.e., differences in transporting RNG from eastern BC to western BC vs. northern BC to southern BC). But the model does have intra-provincial transportation costs as well as inter-provincial transportation costs.

6. In reality, this assumption is likely not practical as DAC placement requires considerations of available energy sources. This said, geographical storage for the captured carbon is considered in the model, as for DAC to be adopted there either has to be storage available within the province or there has to be a pipeline to a province/state with storage.

Slide 75 footnotes

1. In the model version used for this project, gTech and IESD are soft-coupled (partially integrated). In this architecture, gTech determines the electricity demand and passes it into IESD. IESD decides how electricity will be generated and dispatched, but does not feed this information back to gTech. At the same time, gTech runs a parallel electricity module (which is much less complex than IESD as it lacks many key functions, such as hourly load). The overall energy-economy results are therefore reflective of gTech's version of the electricity sector, which can differ from IESD's version of the electricity sector.

2. As previously noted elsewhere, the prevalence of RNG in our results is partly due to our aggressive emissions target (50 Mt CO_2e/year by 2050, compared to 100 Mt CO_2e/year set in a number of other net-zero studies).

3. The discrepancies cannot in principle be reconciled without full IESD-gTech model coupling.

Slide 76 footnotes

1. National Renewable Energy Laboratory (2023). “2023 Electricity ATB Technologies”, see: https://atb.nrel.gov/electricity/2023/technologies

2. Canada Energy Regulator (2023). “Canada’s Energy Future”, see: https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2023/canada-energy-futures-2023.pdf

3. Electric Power Research Institute (2023). “Canadian National Electrification Assessment”, see: https://www.epri.com/research/products/000000003002021160

4. Environment and Climate Change Canada (2022). “Exploring approaches for Canada’s transition to net-zero emissions”, see: https://unfccc.int/sites/default/files/resource/LTS%20Full%20Draft_Final%20version_oct31.pdf

5. Small modular nuclear reactors as defined in our model are plants with power generation capacity below 300 MWe. However, studies are ongoing that look at a range of possible SMnR archetypes that are not explored in our modelling, including very small modular nuclear reactors (vSMnRs) and SMnRs used for simultaneous electricity and heat production. For example, Caron, F. et al (2021). “Small modular reactor (SMR) economic feasibility and cost-benefit study for remote mining in the Canadian north: a case study”, see: https://www.opg.com/documents/smr-economic-feasibility-and-cost-benefit-study-for-remote-mining/

6. Low cost sensitivity only applies to the electricity generation archetype of SMnRs.

7. Natural Resources Canada (2023). “Small Modular Reactors (SMRs) for mining”, see: https://natural-resources.canada.ca/our-natural-resources/energy-sources-distribution/nuclear-energy-uranium/canadas-small-nuclear-reactor-action-plan/small-modular-reactors-smrs-for-mining/22698

Slide 77 footnotes

1. Pricing units differ slightly between sources. For example, Navius NRCAN and Clean Prosperity reports values in 2020 Canadian dollars and Fortis 2022 uses 2021 Canadian dollars.

2. To mitigate this issue, the model assumes that only feedstocks proximal to facilities are used.

Slide 78 footnotes

1. Khan et al. (2022).”Techno-economics of a new hydrogen value chain supporting heavy duty transport”, The Transition Accelerator, see: https://transitionaccelerator.ca/wp-content/uploads/2023/05/TA-Report-4.5_Technoeconomics-of-H2-value-chain_V2-1.pdf

2.Canadian Energy Regulator (2021). “Canada Energy Future 2021: Scenarios and Assumptions”, see: https://www.cer-rec.gc.ca/en/data-analysis/canada-energy-future/2021/scenarios-and-assumptions.html?=undefined&wbdisable=true#hydrogen

3. National Energy Technology Laboratory (2021). “Technologies for hydrogen production”, see: https://www.netl.doe.gov/research/carbon-management/energy-systems/gasification/gasifipedia/technologies-hydrogen

4. International Energy Agency (2022). “Global hydrogen review”, see: https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf

5. Government of Alberta (2021). “Hydrogen Roadmap”, see: https://www.alberta.ca/hydrogen-roadmap

6.Government of British Columbia (2021). “B.C. Hydrogen Strategy”, see: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bc_hydrogen_strategy_final.pdf

7. Langlois-Bertrand, S. et al. (2021) “Canadian energy outlook 2021 - Horizon 2060”, Institut de l’energie Trottier, see: https://iet.polymtl.ca/wp-content/uploads/delightful-downloads/CEO2021_20211112.pdf)
Institut de l’Energie Trottier 2021. Canada Energy Outlook. https://iet.polymtl.ca/wp-content/uploads/delightful-downloads/CEO2021_20211112.pdf

Slide 79 footnotes

1. The accompanying methodology report - Navius Research 2023. Net zero Canada methodology report - can be viewed at: https://www.naviusresearch.com/wp-content/uploads/2023/06/Methodology-Report-for-First-Clean-Prosperity-Paper-2023-06-16.pdf

2. Due to the coal phaseout for electricity generation in Canada, the model does not build new coal-fired generation. This is why the only cost provided for coal power generation is a retrofit cost. The other costs on the list are the cost of building new facilities that are fitted with CCUS.

3. Formation CO_2 refers to the cost of CCUS to address formation emissions from oil and gas production.

Slide 80 footnotes

1. Ocean alkalinization was not modelled in our study, but the reference cost has been examined by Navius.

2. Keith et al. (2018). “A process for capturing CO_2 from the atmosphere”, see: https://doi.org/10.1016/j.joule.2018.05.006

3. Gertner, J. (2019). “The tiny Swiss company that thinks it can help stop climate change”, see: https://www.nytimes.com/2019/02/12/magazine/climeworks-business-climate-change.html

4. Ozkan et al. (2022). “Current status and pillars of direct air capture technologies”, iScience, see: https://doi.org/10.1016/j.isci.2022.103990

5. Realmonte et al. (2019). “An inter-model assessment of the role of direct air capture in deep mitigation pathways”, Nature Communications, see: https://doi.org/10.1038/s41467-019-10842-5

6. Fong and MacDougall (2023). “Engineered carbon dioxide removal in a net-zero Canada”, Pembina Institute, see: https://www.pembina.org/reports/engineered-cdr-in-net-zero-canada-report.pdf

7. Intergovernmental Panel on Climate Change (2022). “Climate Change 2022: Mitigation of Climate Change”, see:https://www.ipcc.ch/report/ar6/wg3/). 1275

8. Kelemen et al. (2019). “An overview of the status and challenges of CO2 storage in minerals and geological formations”, Frontiers in Climate, see: https://doi.org/10.3389/fclim.2019.00009

9. Wang, F. and D. Dreisinger (2022). “Status of CO2 mineralization and its utilization prospects”, Minerals and Mineral Materials, see: http://dx.doi.org/10.20517/mmm.2022.02

10. International Energy Agency (2022). Capturing CO2 from the air can support net-zero goals. https://www.iea.org/reports/direct-air-capture-2022/executive-summary

Slide 82 footnotes

1. Generally, graph notation indicates the source, the scenario from the respective source, and/or the end of value range for that source/scenario. High/low refer to the estimates corresponding to the top/bottom ends of the range for the given scenario. Values are approximate, with some estimated from graphs or discussion in reports and others calculated from publicly available dashboards based on limited known assumptions. The cited studies may have other estimates that are not represented here.

Slide 83 footnotes

1. Torchlight Bioresources (2020). “Renewable natural gas (biomethane) feedstock potential in Canada”, see: https://www.enbridge.com/~/media/Enb/Documents/Media%20Center/RNG-Canadian-Feedstock-Potential-2020%20(1).pdf (Excludes wood-to-gas)

2. Hallbar Consulting (2017). “Resource supply potential for renewable natural gas in B.C.”, see: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/resource_supply_potential_for_renewable_natural_gas_in_bc_public_version.pdf (Takes into account costs and regulations, not all physical resources are included)

3. Pembina Institute (2020). “The future of hydrogen & RNG in Canada”, see: https://www.pembina.org/event/H2RNG

4. Deloitte and WSP (2018). “Renewable natural gas production in Quebec: a key driver in the energy transition”, see: https://energir.com/files/energir_common/181120_Potentiel-GNR_Rapport-synthA%CC%83%C2%A8se_ANG.pdf

5. Norouzi, O., Heidari, M., and A. Dutta (2022). “Technologies for the production of renewable natural gas from organic wastes and their opportunities in existing Canadian pipelines”, Fuel Communications, see: https://doi.org/10.1016/j.jfueco.2022.100056

6. Fortis (2022). “B.C. renewable and low-carbon gas supply potential study”, see: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/renewable-gas-study-final-report-2022-01-28.pdf

7. Canadian Biogas Association (2017). “RNG Ontario”, see: outlook.https://www.biogasassociation.ca/images/uploads/documents/2017/rng/RNG_Ontario_Outlook_Aug_2017.pdf