Canadian Energy Outlook – 3rd edition

Pathways for a net-zero Canada

Horizon 2060

INSTITUT DE L'ÉNERGIE TROTTIER

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About the Institut de l'énergie Trottier (IET)
The *Institut de l'énergie Trottier* (IET) was created in 2013 thanks to a generous donation from the Trottier Family Foundation. Its mission is to train a new generation of engineers and scientists with a systemic and trans-disciplinary understanding of energy issues, to support the search for sustainable solutions to help achieve the necessary transition, to disseminate knowledge, and to contribute to discussions of energy issues. Based at Polytechnique Montréal, the IET team includes professor-researchers from HEC, Polytechnique and Université de Montréal. This diversity of expertise allows the IET to assemble work teams that are trans-disciplinary, an aspect that is vital to a systemic understanding of energy issues in the context of combating climate change.

About the ESMIA Consultants
ESMIA offers a cutting-edge expertise in 3E (energy-economy-environment) integrated system modelling for the analysis of optimal energy and climate strategies. ESMIA puts forward a scientific approach guided by sophisticated mathematical models. The goal behind our implication is to offer solutions that allow achieving energy and climate goals without compromising economic growth. For 20 years, the ESMIA consultants provide a full range of services for the development of economy-wide energy system models for high-profile organizations worldwide. They also provide advisory services that focus on analyzing complex problems such as energy security, electrification, technology roadmap and energy transitions. ESMIA benefits for this purpose from its own integrated optimization model: The North American TIMES Energy Model (NATEM).

About the e3c Hub
The e3c Hub is a multidisciplinary research, transfer and training center of HEC Montréal, specializing in environment, energy and circular economy. Its mission is to contribute to a transition towards a sustainable society and economy, in conjunction with various stakeholders. To do this, the e3c Hub conducts research, runs a scientific program, and designs and organizes training courses and summer schools.

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Introduction

This report, which is part of the 3rd edition of the Canadian Energy Outlook, explores the possible transformation pathways required to achieve net-zero GHG emissions in Canada, with a special focus on the energy system. Produced by independent researchers, it builds on extensive techno-economic modelling to explore the possible transformation of the energy sector over the next decades, the political choices that need to be made to reach national GHG emission objectives, and the shrinking but still considerable gap between the impact of current measures and targets.

Since this exercise comes with its share of choices, challenges and complexity, we begin this document by reviewing the main scenarios, hypotheses and limitations underlying this work.

1.1 Exploring possible pathways to net zero

Energy services are strongly associated with quality of life and standards of living, helping move people and goods, heat and cool buildings, and providing the power to ensure the operation of society as a whole. The link between the provision of these services and the climate crisis is paramount: in Canada, 81% of greenhouse gas (GHG) emissions are directly associated with the production, transport and consumption of energy to provide the above services. Moreover, most other sources of GHG emissions processes also involve energy use, be they from agricultural production or the chemical transformations made possible by the use of energy in industrial processes.

Box 1.1 – The Canadian Energy Outlook series

The first two editions of the Canadian Energy Oulook series were published in 2018 and 2021, led by the Institut de l'énergie Trottier in collaboration with the Pôle e3 of HEC Montreal, with modelling from ESMIA Consultants, with the objective to explore transformations pathways required to achieve GHG emissions reduction targets in Canada. With each edition, the reports grew in depth and breadth, making it difficult to present in a single document. To facilitate the production of the Outlook as well as its understanding, this third edition is published as a series of distinct and complete reports that, together, will represent a coherent and global analysis of the path to a net zero Canada.

The first report, *The State of Energy and GHG Emissions in Canada*, was published in January 2024. It provides a thorough overview of Canada's energy system and GHG emissions sources, policies targeting them, as well as their role in the country's economy (Langlois-Bertrand and Mousseau 2024).

Pathways for a net-zero Canada is the second report in the series, projecting the energy system and GHG sources in the future in a variety of scenarios, and discussing the various impacts on the Canadian energy system and economy more broadly.

In a third section of the project, the Canadian Energy Outlook will provide additional reports that focus on potential developments or challenges facing Canada. These reports will explore, for instance, alternative assumptions for population growth or issues pertaining to specific industrial sub-sectors.

All reports will be available here.

While various pathways are available to transform societies to net-zero emissions systems, a critical assessment of the impacts of these pathways is needed to enlighten policy and investment decisions aiming to reach this objective. As a result, outlooks such as this one, which test various futures in these respects, are essential tools for supporting this task.

This document follows similar work carried out in previous editions of the Canadian Energy Outlook (Langlois-Bertrand *et al.* 2021, 2018). In several ways, its aims and coverage are much closer to the 2021 edition, which was the first to look at the then-recent pledge by Canada and others to reach net-zero emissions by 2050. In the past three years, many efforts to provide an analysis of economy-wide trajectories to net zero have been published the world over, all with the common aim of helping to determine the implications of these targets for all human activities.

The working definition for net zero used in the Outlook matches that set out in the Paris Agreement, where article 4.9 addresses a situation where all emissions under the jurisdiction of the Agreement (from all human activities) must be compensated by carbon removals from the atmosphere. Under this agreement, emissions are accounted for from a production-based perspective: each country is responsible for the total emissions generated directly on its territory, irrespective of the emissions' final beneficiary. For example, the emissions generated during the extraction of natural gas, its transport to coasts and its liquefaction to ship overseas are assigned to the country where these operations are performed, not to that of the final user. Although some technical issues lead to variations in the specific accounting of these emissions—and, by extension, in the exact meaning of being "net zero"—the general idea is that such a society would have no net impact on the atmosphere in terms of GHG emissions, thus limiting its contribution to global warming.

Since the publication of the previous edition of this Outlook, several other modelling reports focusing on net-zero trajectories have enriched the discussion on trajectories and policies. Given Canada's commitment to implement a policy strategy to meet the net-zero target by 2050, two such efforts are particularly important:

- In October 2022, Environment and Climate Change Canada submitted its long-term strategy to transition to net zero, which includes modeling of different options to meet the 2050 target (ECCC 2022), to the United Nations Framework Convention on Climate Change);
- In June 2023, the Canada Energy Regulator released its Canada's Energy Future 2023 report, which focuses on the challenge of achieving net-zero GHG emissions by 2050 (CER 2023).

Others have also provided additional national net-zero modelling efforts for the more specific but substantial task of decarbonizing and drastically expanding electricity networks to make net zero possible (including, but not limited to, AESO 2022; Brinkman *et al.* 2021; DSF 2022; EPRI 2021; IESO 2022).[1]

This report's focus on Canada's situation makes it possible to provide an analysis tailored to the country's particular energy system and enables comparisons with how similar net-zero challenges are met around the world by identifying both commonalities and distinct features. It complements the efforts summarized above by using a technologically deep modelling approach to explore a rich set of optimally costed scenarios. To do so, it adopts a traditional form, projecting Canada's energy production and consumption into the next decades according to these scenarios and its GHG emissions, including those outside of energy-related activities. It also focuses on the transformation that is taking place across Canada's energy sector, its impact on the general economy, and its dependence on various provincial and federal GHG emission reduction measures.

With all these considerations in mind, this report has three overarching objectives:

1. To identify possible pathways to reach the net-zero target with different choices that can be made to achieve these targets from a cost-optimal perspective. These pathways cut across Canada's energy system and other activities specific to certain sectors, such as industrial processes and agriculture. Analyzing how the different pathways affect them is essential to understand the implications of the energy transition that will extend over the decades to come, as well as to highlight some of the choices that Canadians contemplate and the potential these choices hold for improving quality of life in conjunction with the transition.
2. To ensure a thorough discussion of cross-provincial variations within these pathways. Keeping provincial variation in mind is crucial for at least two reasons:
   a. The importance of political efforts to bring about emission reductions varies quite substantially across the provinces, based on differences in the structure of their economies, their population size and its distribution among rural and urban regions, as well as the prevailing preferences, values and ideologies among their residents and political class.
   b. Furthermore, these differences exist in the context of a federation, where a significant portion of jurisdiction for energy matters lies with the provinces. While this situation complicates national initiatives to coordinate emission reduction efforts and transform the economy, it also points to the possibility that thinking in national terms may lead to a more efficient distribution of the transition costs.
3. To provide an extended analysis of the main aspects of reaching net zero, as opposed to merely reducing emissions. This includes infrastructure deployment to support the decarbonization of sectors, key families of technologies to transform energy systems, the capture of some carbon emissions, and how to treat the special case of the industrial sector.

   The analysis presented here is not a crystal ball: it does not predict the future. It instead explores cost-optimal pathways, as measured mainly from the energy system's perspective, in response to external constraints such as the carbon tax or GHG emission ceilings. Without additional analysis, modelling leaves aside questions that are essential to a society, including equity, health, education and more.

[1] These reports, as well as other recent work on these topics, are available for reference on the Canadian Energy Outlook webpage, which can be accessed here.

1.2 Scenarios and key assumptions

1.2.1 The NATEM model

Scenarios presented in this report are all analyzed through NATEM,[2] a techno-economic optimization model of the Canadian energy system with rich technological detail (over 4,500 technologies and 500 energy commodities are included). NATEM covers all energy-related emissions, including fugitive methane emissions, as well as "non-energy" emissions from industrial processes, agriculture and waste. Using a given scenario, NATEM optimizes the total cost for the energy system from now through 2060, while respecting macroeconomic assumptions (GDP, oil and gas export prices, etc.) and meeting demand projections for services provided to the population (square feet of floor space, tonnes of cement and steel, km-passengers, etc.). Population growth is also expected to follow current projections from Statistics Canada's medium-growth scenarios, a point we pay particular attention to throughout this report given the high likelihood that these projections significantly underestimate the trend for the coming years.

Some GHG emissions are not covered by the model: emissions from land-use, land-use changes and forestry (LULUCF) are not addressed, although they are partly touched on through the use of negative emissions applications, a concept employed to describe the use of biomass coupled with carbon capture or emissions stored in biochar. The model also excludes emissions from international aviation and marine bunkers. Moreover, ancillary costs for electricity grids with a very high level of variable generation (such as from wind and solar installations) are simplified through the use of a cost premium on these as well as on storage technologies. Cost assumptions for technologies are presented in Appendix A.

As a techno-economic optimization model, intrinsically, NATEM posits overall cost optimal choices applicable to energy technologies and use between now and 2060. Results therefore represent a lower bound on the energy needed to provide the services assumed in various scenarios. Any inefficiency built-in by sub-optimal choices, as defined by the model, that take place in real life will only increase this energy demand.

Moreover, the selected scenarios presented below do not explore the development of new economic sectors, but only assume uniform growth of Canada's current economy and industrial fabric. Yet, already today, we see that new sectors like artificial intelligence, battery production and mining could grow rapidly and considerably modify our current energy consumption profile. Although it is not possible for us to develop scenarios for each of these potential developments while maintaining a coherent report, we will explore the impact of some of these developments in further reports of this Outlook series, where additional reports will present analytic discussions of key issues.

1.2.2 Scenarios

In this report, a reference scenario (REF) presents these projections to 2060 using no constraints on GHG emissions and includes all energy and GHG reduction policies currently in place at the federal and provincial levels. We then consider a main net-zero scenario (NZ50), which adds a net-zero emissions constraint on total CO_2 equivalent by 2050, as well as a 40% emissions reduction target by 2030 from 2005 levels, reflecting the two legislated federal targets. Price assumptions for energy exports in NZ50 capture a certain degree of variation in climate action around the world in the net-zero scenario, contrary to REF. Otherwise, the net-zero scenario uses the same set of assumptions and includes the same policy coverage as the reference scenario.

As explained in Chapter 3, the importance of specific electricity baseload expansion in net-zero trajectories also led to the inclusion of an alternative net-zero scenario (NZ50PS), where more pessimistic cost projections for nuclear small modular reactors (SMRs) were used instead, to reflect the significant uncertainty about the deployment of this form of electricity generation.

[2] NATEM stands for North American TIMES Energy Model, an energy systems optimization model implemented by ESMIA Consultants. It makes use of The Integrated MARKAL-EFOM System (TIMES) model generator developed and distributed by the Energy Technology Systems Analysis Program (ETSAP) of the International Energy Agency (IEA) and used by institutions in nearly 70 countries.

While scenarios include all GHG reduction and energy policies currently in place at the federal and provincial levels, scenarios also include policies that are currently at the design phase but will likely have an important impact on emissions, that is, the Clean Electricity Regulations (CER) and the Zero-Emission Vehicle (ZEV) sales mandate. The federal fuel charge is also assumed to follow the price increase schedule to \$170/t CO_2e in 2030, after which it increases to follow inflation.

The CER's incorporation, which is modelled after the draft version released by Environment and Climate Change Canada in August of 2023, is assumed not to be applied in the three territories. The ZEV sales target requires all new vehicles sold in 2035 to be zero emission and 60% of sales in 2030 to meet that criterion.[3]

These scenarios were chosen to contribute to the objectives set out in the previous section by outlining the feasibility and implications of net-zero scenarios, and by providing details on what form they would take and what technologies and uses they entail.

All scenarios are based on targets from a national perspective. The model allocates reductions optimally across provinces in order to reach these targets, based on costs and available technologies. As a result, provincial pathways differ in the pace and extent of the transformations to the various sectors and the remaining net emissions in each province vary based on their specific constraints. As Chapter 4 and Chapter 5 show, the results clearly indicate the need for a substantial amount of emissions capture, negative-emissions activities, and direct air capture technologies for emissions to become neutral from a national perspective and compensate for each province's remaining emissions.

Lastly, it is worth noting the following main assumption categories used in the model:

a. Prices of imported and exported energy commodities: the prices used are aligned with the Canada Energy Regulator's Benchmark prices (using the Current Policies scenario for REF and the Global Net-Zero scenario for NZ50 and NZ50PS);

b. Demand projections for energy services: a starting point for energy services demand is built from the reference scenario and NATEM has its own price elasticity mechanisms so that demands react to their own prices;

c. Technological developments: the model uses an emerging technology database based on the literature, where technologies are characterized according to their technology readiness level;

Table 1.1 – Description of the reference and GHG reductions scenarios

Name	Summary description
REF	The reference scenario. No constraining GHG reduction targets. Macroeconomic assumptions (GDP, population, oil and gas export prices) are aligned with the Canada Energy Regulator's projections as well as those of Statistics Canada, imposing no additional constraints in terms of GHG emissions. Includes all GHG reduction and energy policies already in place in addition to the Clean Electricity Regulations and Zero-Emissions Vehicle sales mandate.
NZ50	This scenario imposes a net-zero emissions target on total CO_2-eq by 2050, and a 40% reduction target by 2030, with respect to 2005.
NZ50PS	This scenario is identical to NZ50 except for cost projections for nuclear SMRs, which are higher.

d. Evolution of technical and economic attributes of technologies over time: realistic assumptions about the evolution of technologies and their cost are made based on a review of the literature; mid-point assumptions are made where there are wide discrepancies in projections;

e. Climate change mitigation efforts in other countries: to reflect climate change actions worldwide, net-zero scenarios assume a decrease in demand for exports resulting from price assumptions in CER's Global Net-Zero scenario, reflecting a certain level of climate change action on a global scale.

Where relevant, the report presents a discussion of the impact of each of these assumptions and a number of the associated uncertainties.

[3] Appendix A presents the complete list of assumptions on policies and costs.

1.3 Limitations of and omissions from this Outlook

Modelling exercises like those presented in this document have a number of limitations that derive from the simplifications required and the uncertainty inherent in forward-looking initiatives. Dealing with these limitations requires careful assumptions, beyond those previously discussed in Section 1.2. A few key points are set out below.

The broadening of our emission coverage does not eliminate uncertainty about the likelihood of the advent of disruptive technologies that could be game changers in some sectors and thus affect the pace of some of the results. This uncertainty is typical in this kind of modelling and must definitely be kept in mind when interpreting the results. Since technology pathways with a high degree of uncertainty, such as hydrogen applications, nuclear small modular reactor deployment and some niche technologies, are difficult to model by nature, results are necessarily uncertain. In a similar vein, dramatic changes in consumer preferences for energy services, especially in terms of reducing demand for some energy services, are not considered beyond efficiency improvements throughout the energy system.

As with the previous edition of the Canadian Energy Outlook, this report's focus on energy and GHG emissions has also left aside the important issue of adaptation to climate change that will affect energy consumption/production and the choice of investments in infrastructure. Certainly, the energy transition is as much about technological and economic development as it is about reducing the risks and costs associated with accelerated climate change caused by rising GHG levels in the atmosphere.

Finally, it must be noted that, to a certain extent, our discussion downplays the issue of displaced emissions. Not all technologies required for the extensive transformation of energy services according to the different scenarios will be produced in Canada, and, following the Paris Agreement, we do not evaluate the impact that this shift will have on global GHG emissions. Another example is emissions from oil refineries, which the optimization of the model may reduce by selecting to increase imported refined products instead, even though these emissions will still reach the atmosphere. Although we do not take this issue lightly, this shortcoming is inevitable given our Canadian focus, as well as beyond the scope of our analysis—like many others with a national focus.

Despite these caveats, modelling allows for the identification of general trends, which we believe to be fundamental in setting the bases for a discussion of net-zero pathways for Canadian energy systems. We return to these issues in Chapter 6 in light of our results.

1.4 Overview of the report

The next chapters examine the results obtained from the modelling. The analysis builds on a detailed understanding of the current situation and recent trends in the Canadian energy system and sources of GHG emissions, which are provided in the previous report of the 3rd edition of the Canadian Energy Outlook (Langlois-Bertrand and Mousseau 2024). Comparisons are made across scenarios and across time, with Chapter 2 focusing on energy consumption, Chapter 3 on energy production, and Chapter 4 on the evolution of GHG emissions and the specific question of compensation technologies.

Box 1.2 – The Pathways Explorer

In 2023, the IET collaborated with ESMIA and Kashika Studio to develop the Pathways Explorer, an online interactive dashboard for net-zero scenarios visualization. The tool allows users to compare the impacts of constraints of various nature and quantify the trade-offs they impose on the energy system transformation on a trajectory to net-zero carbon emissions.

In addition to the detailed presentation of the results from this Pathway to a Net-Zero Canada report in the next few chapters, results are also accessible on a dedicated platform for the Canadian Energy Outlook, which uses the visualization tools of the Pathways Explorer. Brief versions of some of the key analyses presented in the following chapters are made available on the Pathways Explorer to provide a glance at the results and main bottom lines from comparison across scenarios and across time. While the text of this report presents key results in a synthesized fashion, the platform enables a deeper exploration of these results.

The platform can be accessed here.

Chapter 5 then presents some of the notable variations across provinces and territories in the dimensions covered by the other chapters to highlight differences in the challenges facing each province and territory. Chapter 6 provides conclusions, promoting a thorough understanding of the challenges to come and the actions needed to effectively reach the desired objectives. This enables us to present policy recommendations to make the shift toward a net-zero future effective.

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2

Reaching net-zero by transforming energy consumption

This chapter presents the first part of the modelling results, examining energy demand and consumption, including an analysis by sector and a focus on the provision of key energy services. Reducing fossil fuel sources in net-zero scenarios leads to a significant efficiency gain overall, one that is largely the result of technological transformations toward more productive energy sources, mainly electricity. Given the cost and availability of technological substitutes, the portrait across sectors is varied both in the mix used and in the pace of the transformation, which is more rapid in sectors with cheaper existing technologies.

Highlights

- While current measures make some transformations more likely, leading to a slower growth in energy consumption, the gap with net-zero trajectories shows that the measures needed to induce the profound changes required by the latter have not yet been deployed.
- Net-zero scenarios lead to substantial transformations in the electricity sector, even before 2030 in some cases.
- Until 2050, net-zero scenarios translate into reduced energy demand due in large part to energy efficiency and productivity gains (notably through electrification). After 2050, however, since most cost-effective transformations with currently identified technologies have been realized, meeting increasing demand from a rising population results in significant consumption growth.
- Net-zero scenarios do not include any expansion of natural gas even over the medium term (2030) because it is largely incompatible with pathways targeting net-zero by mid-century. Natural gas cannot be considered as a transition fuel.
- The transformation of the transport sector will be central to GHG emission reduction efforts.
- Replacement of fossil fuel-powered systems by electricity for space heating constitutes a key contribution to GHG reductions.
- In all scenarios, bioenergy expands from now to 2030 (in large part because of liquid biofuels and syngas), but its limited availability subsequently leads to a transformation in its contribution to decarbonization since its usage becomes concentrated in negative emission technologies.
- Given that few low-hanging fruits remain, changes in the industrial sector are limited in the reference scenario. Emission reductions will require major transformations to processes themselves, with the caveat that many changes will be imposed by global transformations in key subsectors.
- Assessing the exact role of hydrogen is difficult since many uncertainties remain as to how it will be deployed.
- Given the extensive additional infrastructure needed to achieve the net-zero transition, implementation challenges make net-zero trajectories dependent on the rapid development of strategies to deal with labour needs, supply chain issues and social acceptance barriers.

2.1 Energy demand and consumption

Figures 2.1 and 2.2 present the evolution of the total final energy demand (outside the energy production sector) for the reference (REF) and net-zero scenarios.

With the transformations taking place today through regulations, carbon pricing and the evolution of the price of electric technologies, consumption growth is expected to slow in the medium term, even in the REF scenario.

Before 2030, the reference scenario shows that current measures are insufficient to bring consumption growth to a halt, with the total increasing by 6.2% from 2021 levels (7,570 PJ) to reach 8,040 PJ. This rise is overwhelmingly due to growth in the transportation sector as the penetration of more efficient electric vehicles takes more time to compensate for population growth.

Due to electrification incentives and transport sector regulations, REF then sees its overall consumption remain constant between 2040 and 2050. Policy and regulatory measures in REF accelerate the transformations already underway, especially in the transportation sector. This suggests that, if these measures deliver as planned, the impact on total energy consumption will be substantial.

Net-zero trajectories require more profound transformations: current measures are far from sufficient to reach legal targets.

The transformation is more profound in net-zero scenarios, as NZ50 sees total consumption increase by only 1.0% by 2030, due to both a slightly more rapid reduction in transport and reductions in buildings (-11.2%). However, before 2050, total energy consumption in NZ50 is down by 8.9%, in sharp contrast to REF's 4.0% increase.

While transformations in REF over the next decades represent an important departure from today's mix, the constraint on emissions for 2030 and 2050 imposed in scenario NZ50 have a much larger impact on the diversity of energy sources and the total demand. As in REF, oil products diminish in quantity, although the reduction is much more substantial, varying from 32% of the total energy consumption today to 4.2%, which represents an absolute decline of 89% between 2021 and 2050. Furthermore, the use of natural gas remains flat for the next 15 years before dropping dramatically from 2040 in a major departure from the REF scenario.

Figure 2.1 – Final energy consumption by source (excl. energy production)[1]

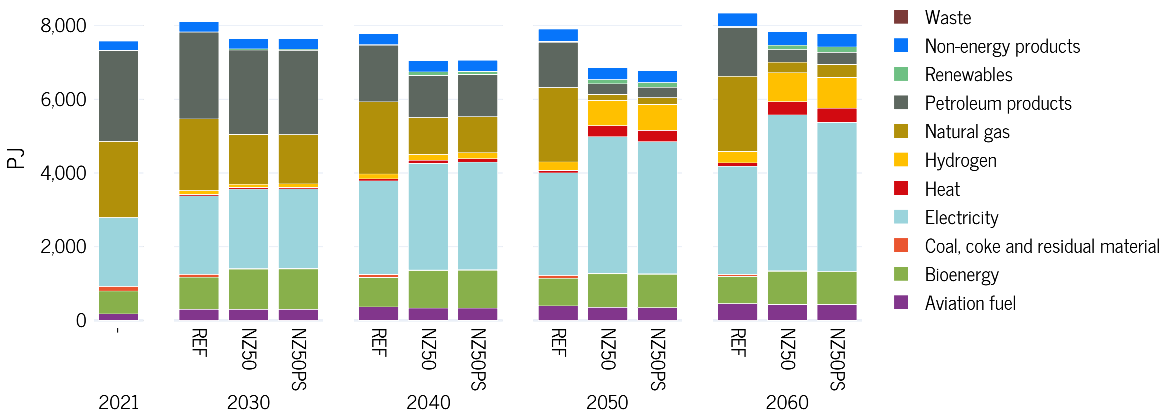
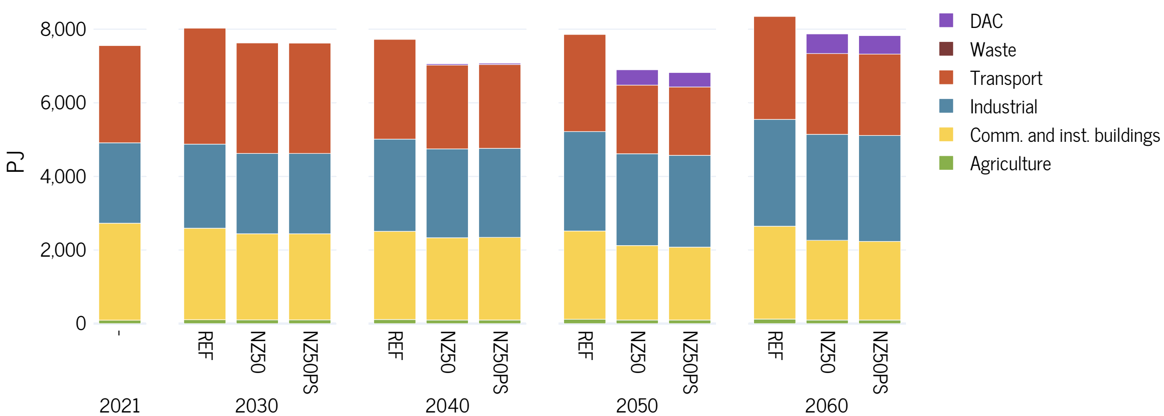


Figure 2.2 – Final energy consumption by sector (excl. energy production)



[1] Data for all figures can be downloaded from the dedicated Pathways Explorer platform, available here.

Apart from the reduced role of natural gas, other major differences in NZ50 compared with REF are reflected in the larger role that electricity, hydrogen and bioenergy play in the mix. Electricity consumption more than doubles by 2050 (108% increase over 2021), rising from 24% to 54% of total energy consumption, while hydrogen grows to represent 10% of the total in 2050. Bioenergy's more modest rise occurs earlier on in the horizon, with a 75.4% increase by 2030 from 2021's 620 PJ. However, it plateaus thereafter at about 1,000 PJ or 13% of the total demand, illustrating both biofuels' important role in the first stage of the net-zero pathway and their limits in a net-zero future.

Due to the productivity of electricity, all sectors see energy demand fall in NZ50.

As mentioned, the NZ50 scenario also results in a significantly smaller energy supply by 2050. For the same energy services (heat, transport, industry, etc.), NZ50 requires 13% less energy (1,052 PJ) than REF. In fact, the overall mix of net-zero scenarios is associated with a much more efficient use of energy, provided in large part by the electrification of many energy services and increased efficiency in part of the building fleet. We unpack these developments and address important caveats in the sections below.

Transformations are more difficult after 2050 as opportunities are more limited, even in NZ50.

While the REF scenario shows relatively stable total energy consumption between 2030 and 2050, this consumption subsequently begins to rise, with an increase of 6% between 2050 and 2060, as population growth becomes the main driver in energy consumption growth. This change in trend can be seen as an illustration of the limits of current policies over the longer term. Nevertheless, the scenario shows significant changes in the energy mix, resulting from current policies as well as projected market transformations. In particular, oil products occupy a much smaller share of the total mix compared with today (16% in 2050 vs. 32% in 2021), while electricity and natural gas show the most sizeable increases in absolute terms. Hydrogen manages to penetrate the mix, especially starting in the 2030s, although at 2.9% its share of the total remains small in 2050.

Interestingly, between 2050 and 2060, energy needs in NZ50 experience an even more important rebound (+14.2%) than REF. This hard rebound illustrates the limits of current information on technology cost and availability, following from the model aimed first and foremost to achieve net-zero emissions by 2050. In fact, efforts are concentrated before that date and all techno-economically viable technologies have therefore already been deployed by 2050, meaning that further opportunities for GHG reductions or efficiency improvements past 2050 are more limited. As a result, the expected growth in demand following from population growth becomes the main driver in energy consumption between 2050 and 2060.

General observations:

- In NZ50, demand for energy services must be met by design. Accordingly, the decrease in total energy demand before 2050 does not lead to a corresponding reduction in the energy services provided. Instead, a large part of the demand for these services is met by more energy efficient technologies and sources, mainly electricity.
- Once net-zero is reached, increases in energy demand are possible without breaching carbon neutrality, as illustrated by the higher total demand in net-zero scenarios in 2060 compared with 2050. However, population growth puts pressure on the energy system to meet additional demand for services, while maintaining net-zero emissions.
- The proposed evolution of carbon prices up to 2030 is insufficient to reach the GHG reductions target for that period.
- In the context of a 2050 NZ horizon, natural gas cannot be used as a transition energy.

Hindsight in energy outlooks: focus on consumption

Looking back at the previous edition of the Canadian Energy Outlook (Langlois-Bertrand *et al.* 2021), several differences and similarities emerge when comparing results with the 2021 edition. Each chapter in this report therefore points to areas where information has improved on how to project ourselves to 2050, in addition to policies since put in place.

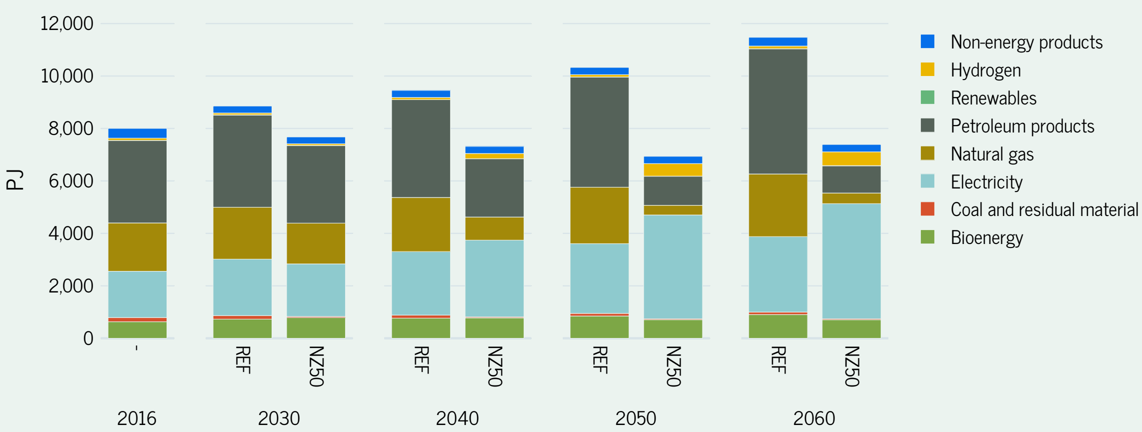
One of the main overarching differences is the evolution of the reference scenario. Since the 2021 edition, many additional policies that have been introduced or are in development have been included in the reference scenario in this edition. This includes the Clean Fuel Regulations, as well as the draft versions of the Clean Electricity Regulations and the Zero-Emission Vehicle (ZEV) sales mandate. The many key transformations expected from this inclusion narrows the gap between the REF and NZ50 scenarios in some sections of the energy system.

For instance, the inclusion of the ZEV mandate leads to a complete electrification of light-duty vehicles in REF, similarly to NZ50. In the absence of additional policies targeting the transport sector, however, this also illustrates the limits of the measures in place, as NZ50 shows a more extensive decarbonization of other subsectors. This is also reflected in overall energy consumption, where the REF scenario shows important efficiency gains in the use of energy. Overall consumption therefore grows much more slowly than in the reference scenario found in the previous edition.

While electricity's role grows similarly in both modelling exercises, some differences in its contribution in key subsectors are noted. For instance, heavy road transport sees more penetration of hydrogen, even though battery-electric vehicles and catenary remain important, as they were in the last edition.

Other similarities in consumption include the rapid increase of bioenergy in net-zero scenarios on the shorter term, after which total consumption is limited due to resource availability and residual emissions, and biomass resources are diverted to the negative emissions activities in industry and energy production.

Figure 2.3 – Final energy consumption (outside the energy production sector) in the CEO2021



2.1.1 Electricity's expanded role

The electrification of many energy services will be a large part of the evolution of the energy system, whether or not net-zero is reached by 2050. Between 2021 and 2050, electricity's role in consumption climbs from 1,953 to 2,860 PJ in the reference scenario, representing an increase of 46% and illustrating an acceleration of the transformations already underway. This increased role helps support the rapidly expanding place of electric cars in a few years, as well as the electrification of several industrial sectors and more extensive use of electric space heating technologies.

> **While electrification is expected to be significant in REF, net-zero pathways require drastically larger quantities of electricity to decarbonize.**

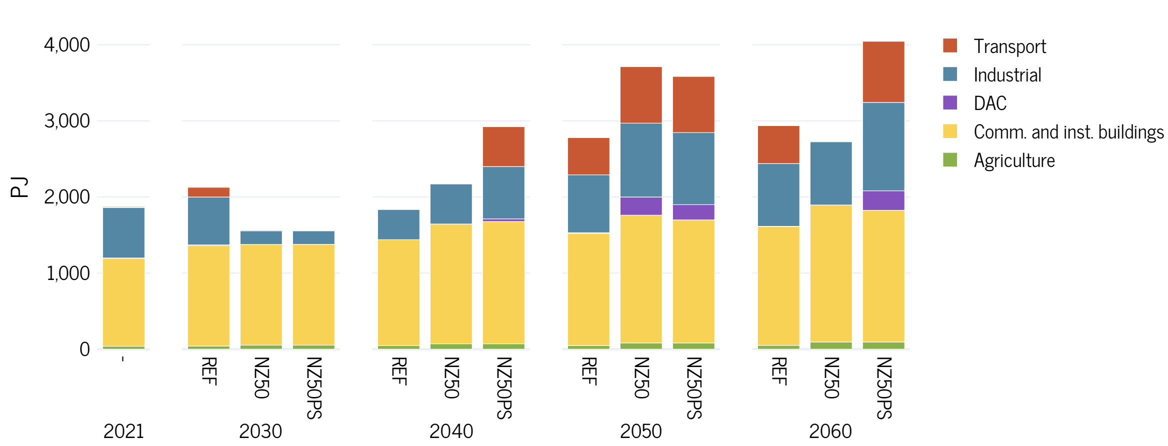
The net-zero pathway represented by NZ50 extends well beyond the levels of electrification found in REF, with a 14.1% increase by 2030 and a doubling of electricity consumption by 2050 to reach 4,060 PJ. As a result, with 54% (up from 24% today) of total final consumption in the sectors, electricity comes to play the largest role in the energy mix in 2050 (Figure 2.4).

It is important to note that this projected increase in electricity's role is a conservative one. It presupposes a mainly constant industrial landscape, therefore excluding demands from new industries, such as battery manufacturing plants, that are likely to become more important in the future. It also assumes that new electric technologies will be adopted with maximal efficiency, which in practice is never fully achieved. **As a result, electricity needs are likely to be even greater than those emerging from NZ50 if Canada is to reach net zero.**

> **In net-zero scenarios, electrification accelerates substantially from 2040.**

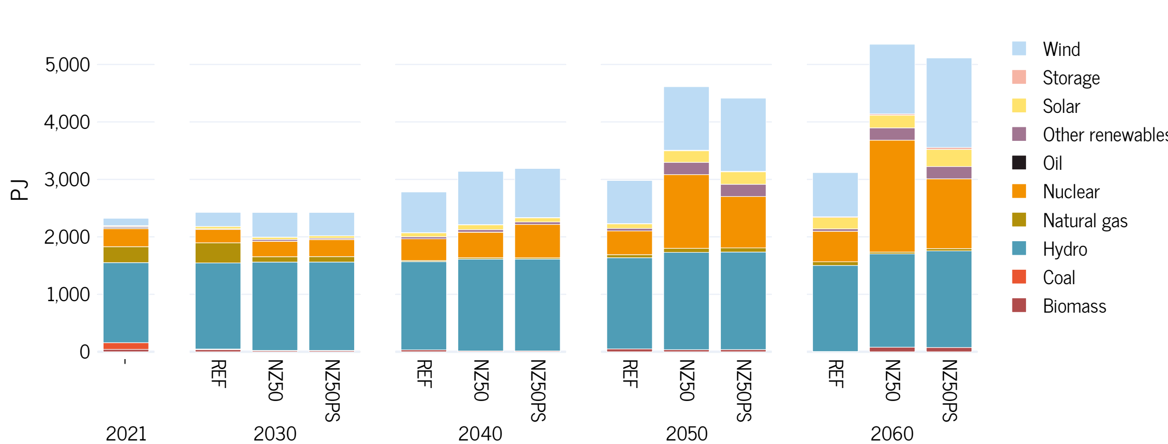
While in net-zero scenarios the increased contribution of electricity to energy consumption by 2050 is significant, the differences with REF are relatively small before 2040. Between 2021 and 2040, electricity use grows only slightly faster in NZ50 than in REF, to 3,140 and 2,780 PJ respectively at the end of this period (Figure 2.5). This is because a large part of the electrification of services is already economical and the measures in place, if fully in effect over the period, would result in REF electrifying services, such as light-duty personal and merchandise transport, space heating and some industrial needs, almost as rapidly as in a net-zero pathway before 2040.

Figure 2.4 – Electricity used by sector



Note: 1 TJ is equivalent to 0.278 GWh

Figure 2.5 – Electricity production by technology



Between 2030 and 2040, the spread between REF and NZ50 grows significantly. In 2040, electricity consumption is up 35.4% in NZ50 compared with today, in contrast to REF's 20.0%. After 2040, this gap becomes even more significant, as policy measures in REF have already taken their full effect and more expensive electrification is completed in net-zero scenarios. As a result, electricity consumption grows a further 46.9% in NZ50 between 2040 and 2050 to meet the net-zero objective, compared with REF's 7.2%.

Maintaining a net-zero economy after 2050 requires significantly more electricity as population growth drives increases in energy consumption.

While the increase in electricity consumption for net-zero scenarios across sectors is rapid between 2040 and 2050, electricity use grows a further 16% between 2050 and 2060. However, the share of electricity in total energy consumption does not expand during this period. This underlines the fact that most economically viable technologies identified in the model have already been introduced to reach net-zero by 2050, making it harder to contain electricity demand while the net-zero objective is maintained throughout 2060.

The growth in capacity suggested by net-zero scenarios implies the resolution of many implementation challenges.

In both the reference and net-zero scenarios, the rapid increase in electricity consumption implies a matching expansion in infrastructure over the next few years and, in the case of NZ50, a spectacular additional fleet of generation available starting in the 2040s. Both these developments require careful planning of needs, which is lacking at the moment, and unless utilities turn around there is a real risk that the growth in electricity grids will be slower than in these scenarios, constraining the electrification process. This risk is in addition to the many electrification challenges, including: the uncertain role of storage options to help integrate larger shares of renewable production; the challenge associated with major upgrades in distribution grids to follow changing consumption profiles; and peak demand management. These issues and electricity production are discussed at more length in Chapter 3.

2.1.2 Hydrogen

While hydrogen's growth is important in NZ50, it does not take off significantly before the mid-2030s when use begins in heavy transport.

In terms of total quantity, hydrogen use does not grow significantly before 2040. However, the transformation in its use begins between 2030 and 2040, driven, on the one hand, by a decrease in the use of hydrogen for oil refining, following a massive reduction in oil production (see Chapter 3), and, on the other, by a small penetration of hydrogen in heavy road transport.

From 2040, hydrogen grows in importance in all scenarios as costs decrease.

After 2040, however, hydrogen use grows in transport even in REF, as costs decrease and it becomes a more interesting alternative for road freight, rising to 122 PJ in 2050 from 12 PJ in 2030. This change in transport is more substantial in net-zero scenarios, with 48% more hydrogen used in transport in NZ50 compared with REF. In NZ50, this also constitutes a doubling of hydrogen used in transport over 2040 levels. These trends continue to 2060 in all scenarios.

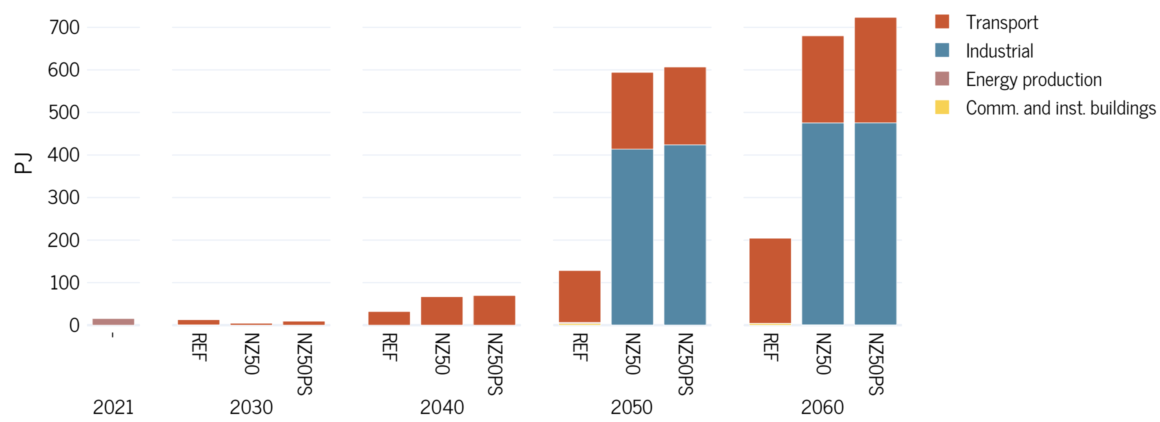
In contrast to REF, net-zero scenarios use hydrogen for a broader variety of applications.

Hydrogen levels used in 2050 for net-zero scenarios depart drastically from REF due to its use in industry (outside of energy production). From virtually nil in 2040, NZ50 sees hydrogen use grow to 410 PJ in 2050, while REF does not use hydrogen in industry. The use of hydrogen for decarbonizing industrial sub-sectors more costly or difficult to electrify explains this boost in NZ50 and is mainly in the manufacturing and pulp and paper industries.

Significant uncertainties surround the specifics of the expansion of hydrogen use.

As we noted in the last edition, while potential hydrogen applications are broad, the considerable uncertainties that remain make this vector difficult to model (see Box 2.1). Hydrogen can play an important role in the evolution of the energy mix, confined to specific applications where it can be most useful, especially when electrification is available only at very high cost.

Figure 2.6 – Hydrogen consumption by sector



Box 2.1 – The cloudy future of hydrogen and bioenergy in net-zero trajectories

Many factors complicate the assessment of the exact role of bioenergy and hydrogen in net-zero trajectories. While cost projections may help determine an estimate of the extent of both these sources across sectors, other factors make the specifics of their deployment more uncertain.

First, both hydrogen and bioenergy sources can be deployed in a host of technologies, many of which are interdependent. For instance, the current lack of distribution infrastructure for hydrogen implies that any construction undertaken in a few years may make some usage more economical than if the buildout took place differently. Industrial hubs for hydrogen production and consumption in particular may lead to a geographical concentration in the deployment of consumption technologies, making the eventual use of some options more likely than others.

Second, significant technological hurdles remain for the transformation, transport and use of both products. While these are given a cost in the model, considerable uncertainties remain as to the ultimate capacity or willingness of the industry to overcome these hurdles as competitive low-carbon technologies also evolve.

Finally, the emissions accounting associated with negative emissions applications of bioenergy, including for the very production of green hydrogen, remains challenging. Given the limited availability of biomass, its use for negative emissions involves a complex balancing of the transition as a whole, including its use in BECCS electricity and hydrogen production as well as biochar, the decarbonization of hard-to-abate applications, etc.

It is therefore difficult to provide a complete portrait of the penetration of bioenergy and hydrogen on the longer term, as several critical uncertainties remain.

2.1.3 Bioenergy

The evolution of bioenergy use shows transformations along the time horizon considered and also subsequent reversals in some. This illustrates both the advantages of bioenergy in net-zero scenarios and the many constraints and limits to these advantages. In terms of constraints on their contribution to decarbonization strategies, the potential of biofuels is limited in net-zero scenarios because their use results in residual emissions, which become more problematic as the net-zero point is approached. Moreover, availability remains a key determining factor: the total quantity of biomass available is not infinite and many upgrade processes result in significant energy loss along the way. A careful balancing act in maximizing the contribution of the resources to net-zero pathways is therefore needed.

Driven in part by the Clean Fuel Regulations, bioenergy increases dramatically in the short term.

Bioenergy use grows rapidly in the short term in both the reference and net-zero scenarios. In REF, final consumption of bioenergy rises 40% before 2030, from 620 to 870 PJ, while in NZ50, the growth is more substantial, reaching 75% more than current levels (1,090 PJ). In all scenarios, 2030 represents a plateau in bioenergy production, after which levels remain similar in absolute terms until 2050. This is the result of both the Clean Fuel Regulations and the relatively low cost of bioenergy as a decarbonization tool in the current context, as other strategies and transformations take more time or require decreasing costs first.

The plateau in bioenergy use from 2030 to 2060 hides a deep transformation in its use, with some usage disappearing altogether over time in net-zero scenarios.

The relative stability in bioenergy levels after 2030 conceals important breakdowns. In the buildings sector, NZ50 eliminates wood-based bioenergy in space heating by 2050, in complete contrast to REF, where 127 PJ (17% of all bioenergy) are still burned for that purpose. In industry, bioenergy's role grows slightly on the short to medium term (2030 and 2040), as some reductions in GHG emissions result, while more expensive transformations are delayed to the 2040s. In transport, biofuel use doubles by 2030, following Clean Fuels Regulations, and then grows a further 50% by 2050, but not without a transformation in its use. After 2040, biofuels disappear from road transport, although they grow significantly in off-road transport. More expensive advanced biofuels generations are used as a way to decarbonize off-road vehicles, where fewer alternatives are currently available.

One key change is the increase in bioenergy with carbon capture and storage (BECCS) applications and biochar production, which are used to produce negative emissions in NZ50.

Bioenergy also serves to produce electricity and hydrogen. While the net-zero scenarios progressively retire wood-fired electricity production by 2050 to reduce emissions, this production is replaced with CCS-equipped facilities, which also produce negative emissions. Similarly, net-scenarios make use of syngas, where the production process creates biochar that is used to store emissions, also resulting in negative emissions.[1] After 2040, bioenergy with CCS also produces negative emissions through hydrogen production, with biomass gasification facilities equipped with CCS. Finally, the treatment of biomass emissions is subject to change over time as better estimates of land-use, land-use change and forestry (LULUCF) emerge (see Box 2.1).

[1] For a more in-depth discussion of this use of biomass, please see Chapter 4, which discusses GHG emissions more directly.

2.2 Energy demand by sector

The evolution of energy demand must also be seen as a function of the economic sector in which the energy is used (Figure 2.2). As discussed above, total final energy consumption in sectors outside of energy production (in buildings, transport, industry and agriculture) deviates from the distribution seen in REF in the net-zero scenarios even by 2030, and then significantly more for later decades. By 2050, not only is total energy consumption 12% smaller in NZ50 (6,900 PJ) than in REF (7870 PJ), but also, as we indicate in this section, the energy mix is very different.

It is important to note again that this lower energy consumption should not be interpreted as a proportional reduction in the provision of energy services, but rather as a demand met with higher efficiency low-carbon energy sources, notably electricity. A closer look at sectors, and also at the transformations in the energy used in each of them, is therefore crucial to more clearly understand the dynamics of decarbonization over time.

2.2.1 The residential and commercial sectors

The consumption of electricity in buildings evolves rapidly in all scenarios since technologies like air source heat pumps are already mature and relatively low cost.

The availability and relatively low cost of more efficient electric heating technologies like cold-climate heat pumps lead to an increase in this technology's role even by 2030. As a result, electricity's share of buildings energy consumption grows in this short period to 57% in NZ50, compared to 43.9% today, an increase similar to REF's. This rate of change on the very short term should be treated as optimistic. Labour shortages, supply chain and other implementation challenges, such as the end of federal subsidy programs, may slow this transformation.

This short-term increase in electricity's role is largely related to space heating systems replacing fuel oil and propane, which rapidly decrease. Natural gas also loses significant shares by 2030, declining by 51% (to 620 PJ) from current levels in NZ50 and 24% (to 950 PJ) in REF, while bioenergy (largely driven by syngas) increases by 136% by 2030 (270 PJ).

After 2030, transformations accelerate in NZ50, decreasing total energy used compared with REF

On the longer-term, electricity continues to grow in importance and rapidly increases its share to reach 82.9% of energy in buildings in 2050 in NZ50, compared with 61.4% in REF. The increased efficiency from the widespread use of air-sourced heat pumps, as well as a more modest but important contribution from solar thermal and geothermal after 2030, results in a significantly lower total energy use in buildings in NZ50 over the longer term. In 2050, this total is 16.7% lower in NZ50 than with REF, despite meeting similar demand and benefitting from similar improvements in energy efficiency through retrofits.

Bioenergy contributes on the short term but is diverted from buildings thereafter.

Bioenergy also grows its share on the short to medium term in NZ50. Syngas grows rapidly, peaking in 2030 and then decreasing mainly after 2040. In the net-zero pathway, the key advantage of syngas production is the biochar by-product, which results in negative emissions for the operation (see Chapter 4).

Aside from this exception, bioenergy all but disappears from buildings in NZ50. In contrast, the contribution of bioenergy remains more or less the same over time in REF, with the only notable change being limited to a short-term increase in renewable natural gas to follow current mandates.

While natural gas used in buildings is expected to fall in relative terms, net-zero trajectories avoid it altogether as it is less costly to move to zero-emission solutions than to have to compensate emissions elsewhere.

One of the key differences between REF and NZ50 relates to natural gas. Even though the use of natural gas continuously decreases in REF over time (-24.2% in 2030 and -45.7% in 2050 compared with today), it retains an important share of the total in 2050 (28.2%), even as electric technologies take over alongside district heating.

In NZ50, in contrast, natural gas is almost eliminated after 2040. The significant emissions associated with its use and limited feedstock availability for renewable natural gas makes its potential contribution to a net-zero future very limited. It is therefore more useful in areas other than buildings, where alternatives are more expensive.

Although district heating's potential role may be substantial, it is difficult to assess given limited past experience with the technology in Canada.

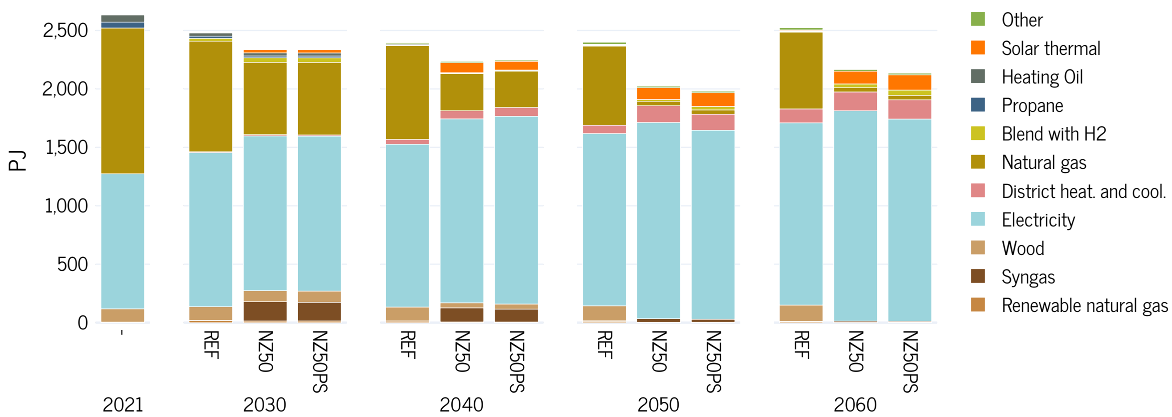
District heating plays a small role in both REF and net-zero scenarios from 2030 to 2050, reaching 1.7% (REF) and 4.9% (NZ50) of the mix at the end of this period. While this potential should be noted, modelling limitations with respect to fine-grain urban development as well as cost and technological uncertainty require careful treatment of these results, since the source of heating in the model largely derives from waste heat recovery from nuclear SMRs and geothermal heat production. Neither of the latter currently exist at any considerable scale in Canada and require new infrastructure for heat distribution. In general, this particular technology's role is difficult to assess over the longer term since its deployment is linked to other key infrastructures associated with waste heat recovery.

Energy consumption levels in NZ50 scenarios assume significant energy efficiency improvements and deep retrofits, making projections a lower bound value for the energy required to deliver the services.

It is important to note that these results include a very aggressive push for energy efficiency improvements and limited demand control measures in buildings. Energy savings due to retrofits and other measures reach the equivalent of 7% of total consumption in 2030, while in 2050 this figure grows to 19% in NZ50 and 16% in REF.

Although this share is significant, these results do not take into account implementation challenges in terms of labour or rebound effects, rendering this result optimistic at best. Nevertheless, these numbers do indicate what basic improvements in buildings could be achieved through well-known technologies and higher standards if done well.

Figure 2.7 – Final energy consumption in buildings



General observations:

- The projections show that natural gas is not a transition energy for buildings since its use virtually disappears in the net-zero scenarios.
- Transformations in the building sector compatible with net-zero are already under way, as reflected in REF, since heat pumps, improved building envelopes and other technologies result in important efficiency gains while eliminating emissions; however, the pace and extent of transformation in REF is far from sufficient to meet the requirements of a net-zero pathway.
- As electrification of building heating increases the winter electric peak demand, various strategies not modeled here will need to be implemented to limit overbuilding electricity production and distribution infrastructure.

Box 2.2 – Implementation challenges of a net-zero trajectory across sectors

While the assessment of net-zero trajectories often focuses on technological transformations or cost-related issues, it seems essential to point out that they are far from adequate to provide sufficient understanding of the challenges associated with realizing the transition. Given that the transformations suggested by net-zero trajectories are more profound and rapid than often realized, severe implementation challenges limit the likelihood of achieving at least some of these modifications to the energy system at the pace required to attain net-zero by 2050.

First, the drastic expansion in electricity's role in the energy mix requires a buildout of new capacity on a massive scale, equivalent or larger than the development observed between 1960 and 1990. This expansion will bring challenges in terms of labour availability for both the construction and the operation of the grids, in addition to supply chain constraints for key components of generation, transmission and distribution upgrades. Moreover, the implementation of electrification is further complicated by the fact that, by definition, capacity must be built well ahead of consumption increases to limit sunk investments.

Second, labour demand for the electricity buildout is partly in competition with other sectors, including for decarbonization efforts. For instance, accelerating deep building retrofits and heat pump installations also requires workers in the hundreds of thousands on a national scale, making it less likely that ambitious objectives will be reached at the pace imagined for the sector without aggressive strategies to manage these needs, improve productivity and streamline regulatory constraints.

Third, some infrastructure choices remain to be made, especially in sub-sectors where decarbonization has not yet started and where policies have yet to orient the direction to be taken on the short to medium term. This is the case for heavy transport, for instance, where high costs and needs for new distribution infrastructures–be it for hydrogen, catenary lines or high-capacity charging infrastructure–require political decisions on ways forward.

These and other implementation challenges point up the urgent need for coherent plans to 2050 across all provinces and at the federal level, including subsector-specific roadmaps and built-in frequent progress assessment mechanisms.

2.2.2 Transportation

Current policy measures are likely to result in major changes in the transport sector, mainly through the extensive electrification of light-duty vehicles.

Similarly to the buildings sector, the main trends in the evolution of the energy mix for the transportation sector show significant similarities between REF and NZ50. Electrification constitutes a key part of this evolution, resulting in a much smaller share of oil products, even in REF (fulfilling 73% of demand in 2030 compared with 89% in 2021).

This is largely a result of the expected growth in electric vehicles, driven in part by the zero-emission vehicle (ZEV) mandate and current purchase incentives. This impact, which is particularly notable after 2030, results in a steep decrease of energy consumption for the sector between 2030 and 2040 even in REF (-14% or 440 PJ). By 2050, REF sees the share of oil products halved with respect to 2021, down to 44.6% of total energy consumption in the sector, with electricity now 18.5% of the total. Given that energy consumption by kilometre travelled is about three times lower with an electric vehicle than with an internal combustion engine, even with REF the service provided with electricity would be significantly more efficient than with oil products by 2050 for this scenario.

Net-zero pathways require much more than the electrification of small vehicles.

While changes in REF are certainly substantial, they are far from sufficient to put the sector on track to a net-zero pathway. In NZ50, for instance, the share of oil products in the mix for the transport sector is already down to 49.1% of the total in 2040. More importantly, the drive to reduce this share after 2040 accelerates to bring oil's share in this sector to a mere 15% in 2050, with electricity growing to 40%. A closer look at the evolution of subsectors is essential to complete this assessment.

Both the energy mix and the available technological and fuel options vary significantly across sub-sectors, making decarbonization very uneven.

In road passenger transport, electrification is virtually total by 2050, including in REF where it satisfies 95.4% of demand. While this is a direct result of the inclusion of the ZEV mandate in the reference scenario and expected worldwide trends, the evolution of supply chain constraints may make this transformation less smooth than expected.

Figure 2.8 – Final energy consumption for the transport sector, by fuel

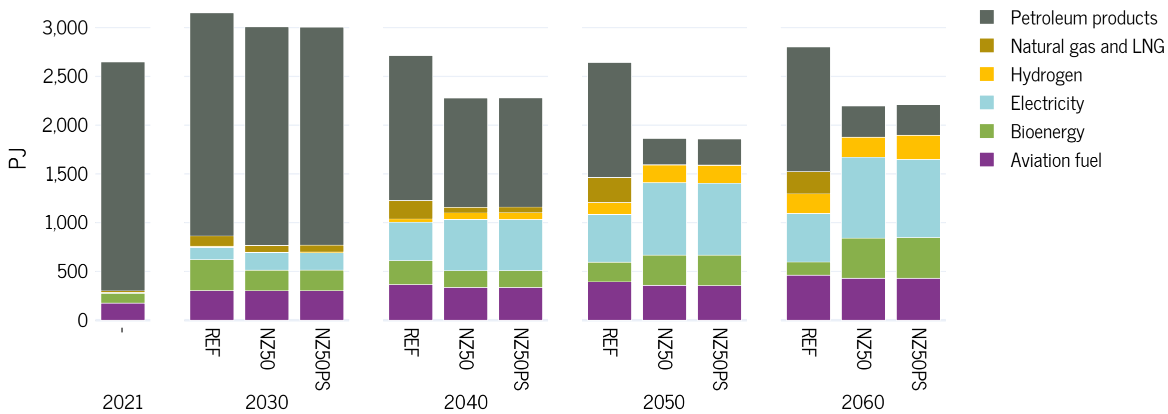
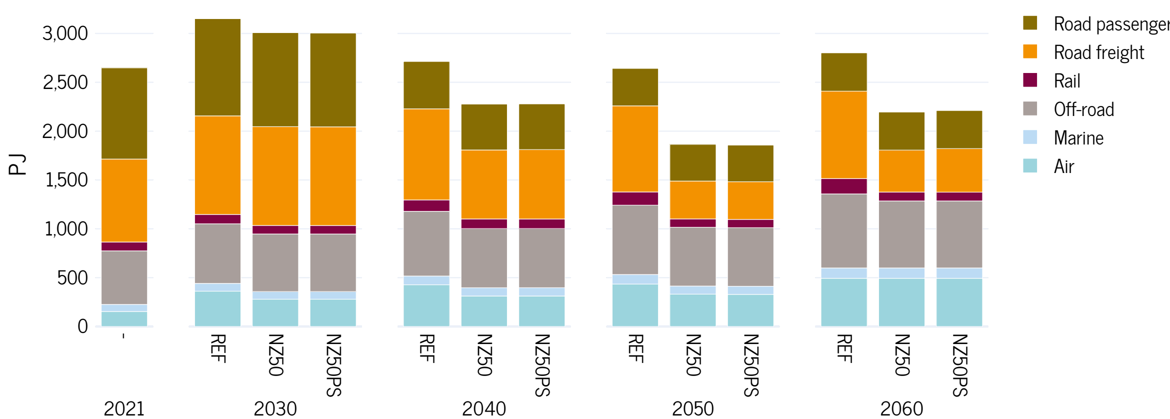


Figure 2.9 – Final energy consumption by transport sub-sector



Decarbonization in freight transport is possible with known technologies but remains associated with uncertainties as to the exact technology mix.

In road freight transport, although electrification is important in REF, most transport subsectors see the advent of hydrogen and natural gas as the preferred source (Figure 2.11). The extensive use of natural gas, which comes to supply 28% of heavy road transport, limits the decarbonization of freight transport. In NZ50, in contrast, decarbonization is virtually total, with a combination of battery electric, hydrogen and catenary being deployed from the mid-2030s.

The technology for the road transport of freight is eclectic in contrast to passenger road transport. While light and medium commercial transport transform similarly to the passenger sector, with almost complete electrification, heavy transport uses a more diverse set of technologies, including hydrogen and catenary lines, but is nevertheless fully decarbonized by 2050.

In the absence of regulations orienting the transformation for heavy road transport, detailed results should be treated with care.

Each of the three main options–hydrogen, catenary and battery vehicles–in heavy freight transport requires a very substantial buildout of distribution infrastructure, which will likely be chosen from a variety of factors beyond pure costs, including political preferences, regional specificities and decisions made south of the border. As a result, the dominant technologies for heavy road transport could be drastically different from those described above, depending on these decisions and preferences.

Moreover, since combinations of technologies are not considered in heavy freight transport, the importance of key options being discussed today is understated. More specifically, the development of integrated systems for particularly important corridors, such as combinations of catenary lines with smaller on-board batteries and lighter charging infrastructure, could present cost advantages that are not reflected in the results presented here (see for instance Whitmore *et al.* 2023).

Overall, therefore, the most important aspects of the results for net-zero scenarios in freight transport are the virtually complete decarbonization of the sub-sector by 2050, the availability of multiple competing technologies, and the fact that a large part of this decarbonization occurs after 2040. Given the significant investments required to make these options available in the next few decades, planning for deployment should be made as soon as possible.

Figure 2.10 – Road passenger transport demand by technology

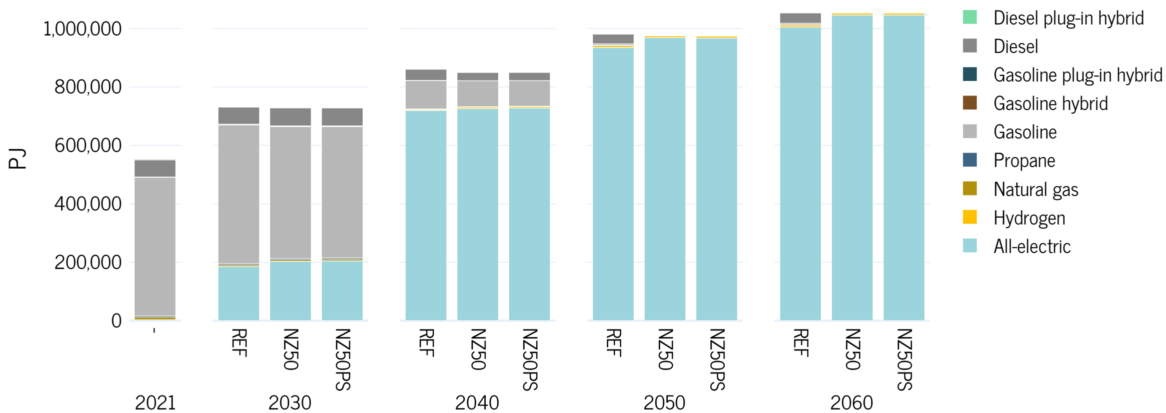
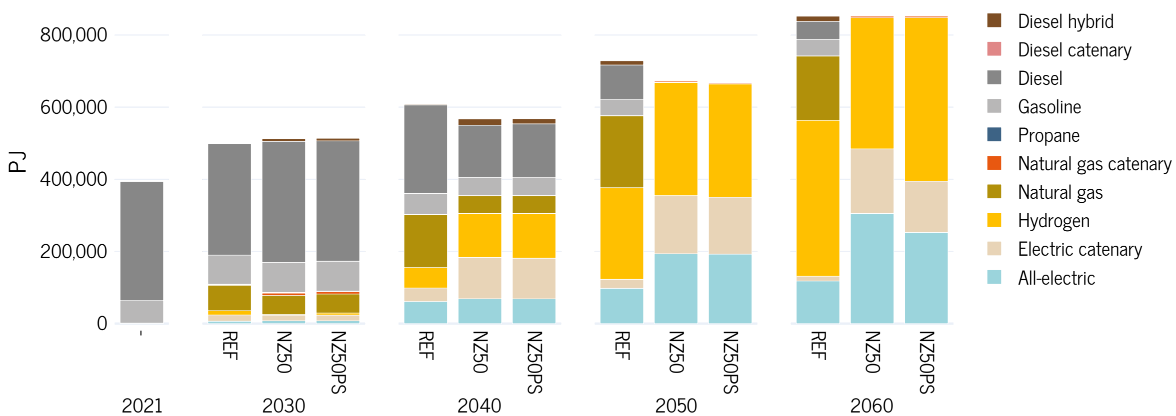


Figure 2.11 – Freight road transport demand by technology



These transformations in road transport combine to make a much more energy-efficient sector.

It is difficult to understate the efficiency gain provided by moving away from internal combustion engines for road transport. In passenger vehicles, for instance, the energy consumed in 2050 is 49% less than in 2021 in both REF and NZ50, despite a 31% growth in population. For the sector as a whole, NZ50 sees a drop of 29.6% in total energy consumed by 2050.

Decarbonization of rail is complete in net-zero pathways.

In NZ50, rail transport ends up fully decarbonized by 2050 with close to a 50% share each of hydrogen and electric technologies. Electricity is the first to appear in large quantities, representing 35.9% of energy demand for rail by 2030, in comparison to virtually zero today. Although hydrogen appears later in the 2030s, it grows to become the largest share by 2060 (60.8%). The decarbonization in NZ50 results in a more efficient use of energy, with total consumption at 37.0% less than in REF in 2050.

The scenario is drastically different for REF: while electricity grows quickly on the short term to 24.0% of energy consumption by 2030, further growth in electric trains is negligible, and 74.2% of demand in 2050 is still satisfied by diesel. These figures clearly suggest the need for measures to initiate transformations to low-carbon solutions.

Air and marine transport's decarbonization is limited and will depend on further technological innovation.

While known technologies enable rail to decarbonize fully, similarly to road transport, in the net-zero scenario, transformations in other transport subsectors are more limited. Bioenergy increases rapidly in REF to 43% of energy consumption in domestic aviation in 2030, but no further after 2030. In NZ50, bioenergy's role is virtually inexistent as the limited biomass resources are distributed to more efficient decarbonization use elsewhere in the economy and greater efficiency is the only notable change in aviation. This highlights the substantial costs associated with current projections for sustainable aviation fuels.

Bioenergy plays a somewhat larger role in marine transport: as early as 2030, biofuels account for a 19% share of energy consumption (from 5.9% today) in both REF and NZ50. Later growth in bioenergy is more limited, while its use in net-zero scenarios is only marginally greater than in REF. The main difference between net-zero scenarios and REF is in the use of hydrogen, which supplies 14% of energy in 2050 and 2060 in NZ50. In total, only 35.3% of energy consumption is from bioenergy and hydrogen by 2050, the rest deriving from fossil fuels. Nevertheless, this results in the sub-sector using 17.9% less energy in 2050 than in REF.

Both these sectors illustrate the limits of bioenergy applications in a comprehensive decarbonization strategy, where competing possibilities lead to biomass resources being used in sectors where it is most cost effective in delivering emission reductions. However, this also points to the considerable opportunities for innovations in these subsectors, which could transform these projections over the longer term.

The lack of attention to off-road transport must be remedied as the sub-sector's importance for net-zero pathways grows.

Off-road transport includes moving vehicles used in industrial and commercial facilities, agriculture and recreational activities. It is the third transport sub-sector in terms of energy consumption after road freight and passenger transport, with 20.7% of total energy consumption for transport. Importantly, its share of total transport emissions grows to 40.9% by 2050 in REF and to 56.8% in NZ50. Despite this key role, it is often omitted or downplayed in discussions about the energy transition in the transport sector and decarbonization efforts for the sector.

As discussed in Chapter 4, this lack of attention is due to a host of factors, including the wide variety of services provided under this sub-sector. Given how eclectic the off-road sub-sector is, it comes as no surprise that the fuel mix evolves differently, depending on usage. Two important trends make it possible to differentiate sharply net-zero scenarios from REF. The first is in industrial, commercial and recreational activities, where bioenergy supplies 69.5% of total energy consumption in 2050 in NZ50 instead of 5.2% in REF, with most of the transformation occurring after 2040. The second is in agriculture, where electricity is the most important change, accounting for 18.5% of the mix in 2030 and 67.9% in 2050, compared to nothing today. This is also in sharp contrast with REF for the sector, where there is only a marginal use of electric technologies.

Grasping the situation and tailoring action to the variety of challenges and expected developments in transport is central to any net-zero strategy.

Overall, these modelling results illustrate the crucial importance of the transport sector in GHG emissions reductions, together with the need for decisive policy action to help achieve substantial GHG reduction targets. While the significant attention paid to small road vehicles is expected to initiate electrification with levels compatible with a net-zero pathway, the high costs and needs for new infrastructure in other sub-sectors (see Box 2.2) lead to transformation difficulties since electrification remains expensive and biofuels offer only short-term and limited advantages in terms of GHG reductions.

General observations:

- The electrification of the transport sector projected for NZ scenarios translates into a 29.6% reduction in total energy demand, which demonstrates the remarkable inefficiency of combustion engines, imposed by the laws of thermodynamics.
- For heavy transport, the transformation of the sector depends on a number of competing technologies that have not yet reached the market on a large scale. Because of the importance of standardization and the need for technology-specific infrastructures (recharging, catenaries, hydrogen), the relative weight of these technologies will be largely determined by political choices rather than by cost. An approach taking into account regional characteristics on main transport routes may also be more effective given the various options.
- Due to a lack of attention, the off-road sector plays a large role in maintaining substantial transport emissions in 2050 in all scenarios
- The transformations of marine and air transport are more costly and suffer from the absence of techno-economically viable solutions, underlining the importance of keeping demand growth in check for these subsectors as a key component of the net-zero trajectory while expanding investments to develop technologies further.

2.2.3 The industrial and agricultural sectors

Energy consumption in the reference scenario increases to keep pace with demand, mainly supplied by a larger share of natural gas.

The REF scenario shows industry (outside of energy production[2]) increasing its final energy demand by 23.1% in 2050. This reflects the limited economical opportunities for transformations as most of this increase is associated with growth in demand. The main change in the mix stems from a large increase in natural gas consumption, which jumps from 692 PJ in 2021 to 1,010 PJ in 2050 (a 47% increase) as its share of the total rises from 30% to 36 % over this time period. Aside from natural gas, the overall mix in REF sees few changes over time: electricity grows only marginally (15%) in REF, and less efficient fuel sources like coal, coke and oil products decrease over the period as well in REF.

Transformations in the energy mix used in industry in NZ50 differ sharply from REF, especially after 2030, including a projected deep reduction in natural gas consumption.

NZ50 differs significantly from the evolution in REF. The greatest change by far compared with REF is the rapid reduction in natural gas, for which consumption in 2030 is down 19.1% from today's levels. The reduction accelerates over time, reaching levels of natural gas consumption 85.5% lower than that of today by 2050 (100 PJ), in direct contrast to the increased use of this fuel in the REF scenario.

While part of this evolution occurs alongside a lesser overall energy consumption for the sector, two key differences in the energy mix for NZ50 must be highlighted. One is the advent of hydrogen as a key fuel after 2040, in contrast to its virtual absence in the energy mix for the sector in REF. While only still marginal in 2040 in NZ50, with 92 PJ, hydrogen use increases almost sixfold to 581 PJ or 17% of total energy consumption for the sector in 2060.

[2] Given the size of the energy production sector in Canada, we distinguish it from the rest of industry for the assessment of scenario results in relation to energy consumption. The next section examines energy use
in the energy production sector, while energy production itself is discussed in the Chapter 3.

While bioenergy plays a larger role in decarbonizing the sector before 2030, electricity's role in industry expands in NZ50, but only from 2040 as a result of fuel switching in several sub-sectors.

Electricity is the second energy source that plays a much greater role for industry in NZ50. While its use remains at similar levels until 2040, it subsequently increases sharply, reaching 46.3% of current levels (970 PJ) by 2050 and 79.8% (1,190 PJ) by 2060. This highlights both possible efficiency gains over the shorter term and the role that bioenergy plays as a transitional replacement for natural gas, while broader electrification–and the eventual advent of hydrogen–takes more time to penetrate and bring down costs. Similarly to the transport sector, this eventual short-term advantage of bioenergy is limited on the longer term as residual emissions and limited feedstock availability make its replacement by electricity and hydrogen more cost-effective to reach net-zero from 2040.

A glance at NZ50 transformations for the entire sector can be misleading since subsectors face both different challenges in decarbonizing their operation and varying opportunities and solutions to meet them.

Accordingly, it is important to take a closer look at the modelling results for key subsectors. In cement production, for instance, natural gas plays a larger role in NZ50 compared with REF (42.3% vs. 12.1% in 2050), even starting in 2030 (35.0% vs. 18.4%), replacing more carbon intensive coal and coke, oil products and waste fuel (process emissions are addressed in Chapter 4).

In pulp and paper production, decarbonization in NZ50 occurs mainly through an increase in bioenergy at the expense of natural gas. After 2040, NZ50 progressively replaces bioenergy with hydrogen, continuing the long-term decline of natural gas. The use of bioenergy in the pulp and paper industry is in fact one of the key applications of BECCS negative emissions processes in industry (see Chapter 4).

Given that some transformations in key subsectors are likely to evolve quickly, driven by worldwide changes, decarbonization strategies for each subsector must take this competitive environment into account and quickly develop roadmaps for decarbonization opportunities. The link with decarbonization plans for key industrial processes is essential and must be tailored to the specifics of each subsector.

Figure 2.12 – Energy consumption in industry (outside of energy production)

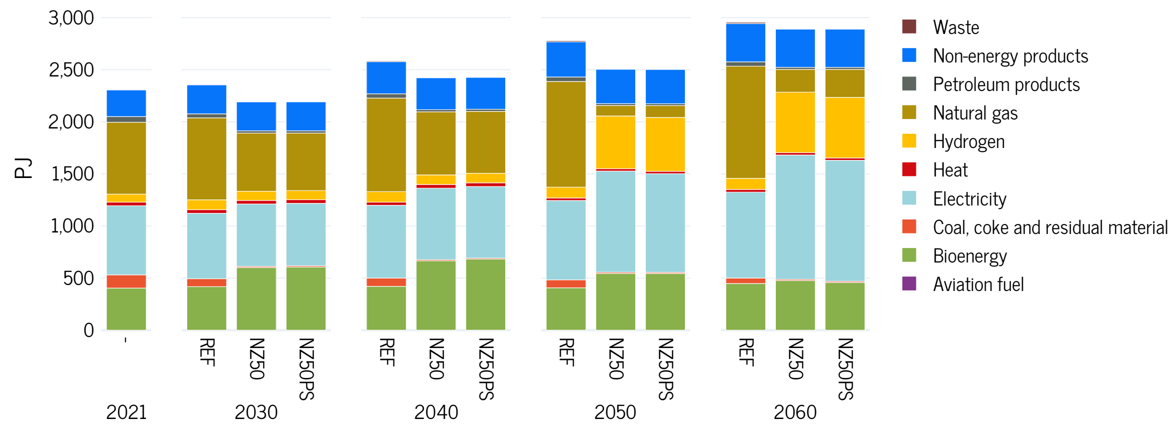
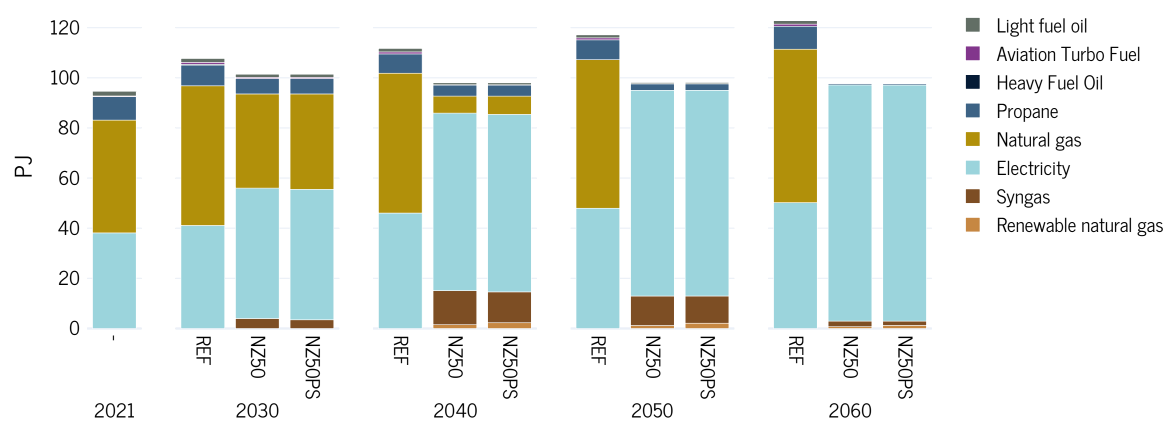


Figure 2.13 – Energy consumption in the agricultural sector



Given current information on technologies using energy in the agricultural sector, electrification options make decarbonization possible at relatively high cost in NZ50.

Energy use in the agricultural sector, which includes heating and lighting but excludes machinery (which is categorized under the off-road transport sector), is almost completely electrified in NZ50 by 2040. This transformation is not sufficiently driven at the moment, as electricity climbs from 51.3% of the mix by 2030 from 40.3% today in NZ50 but barely increases over the same period in REF. Syngas also plays an important role in NZ50, especially from 2040 (13.8% of the total in NZ50), while as a result natural gas is completely eliminated by 2050.

Changes in REF are almost negligible, with a mix evolving more or less proportionally with total demand for services in the sector. This results in both limited decarbonization and much higher levels of overall consumption.

These distinctions highlight the relatively high cost of decarbonization in the agriculture sector and the lack of policy efforts, as well as the difficulty in replacing specific demands (such as for propane) for large-scale heating and drying of crops.

General observations:

- The current energy mix in the industrial sector, where bioenergy and electricity already play a major role, suggest that few low-hanging fruits are available to decarbonize on the short to medium term. NZ50 sees a rapid decarbonization of remaining sources (notably natural gas) after 2040 to meet the net-zero constraint.
- Hydrogen comes to play an important role in this post-2040 decarbonization, especially in the manufacturing and pulp and paper sub-sectors.
- As we noted in the previous Outlook, the electrification of heat in agriculture, while cost competitive, may require specific programs and attention as heat is used for a number of different purposes, some of which, such as drying harvests, require considerable power. The use of locally produced bioenergy, which at this scale is not included in the model, could certainly complement electricity use in this sector.

2.2.4 Consumption for direct air capture operations

Even the limited reliance on direct air capture and sequestration (DAC) in net-zero scenarios would significantly raise overall energy consumption.

A final note on sectoral energy consumption pertains to the impact of energy used to power direct air capture and sequestration (DAC). Due to very high costs, DAC appears only in net-zero scenarios, marginally in 2030 and 2040, but growing substantially by 2050. These operations are an essential part of net-zero scenarios in order to balance remaining emissions. While we examine this issue in greater detail in Chapter 4 on GHG emissions, it is worth noting here that the energy consumption for DAC is significant, representing around 6.0% of final energy consumption in sectors in 2050, increasing further to 6.8% by 2060. This significant share of the total energy consumption occurs even though the levels of DAC required to reach net-zero in these scenarios are relatively modest, at around 30 $MtCO_2e$ of negative emissions (see Chapter 4).

2.3 Consumption and waste in the energy production sector

In examining the evolution of energy consumption in net-zero scenarios, careful attention must be paid to how a trajectory affects energy used and transformed in the energy production process.

A discussion of energy consumption in scenarios to reach net-zero is incomplete without a thorough examination of energy use in the energy production sector. By definition, the transformations in the country's energy mix involve a change in supply, which in turn must derive from transformations in this sector's structure. Furthermore, decarbonizing the economy in Canada necessitates a re-examination of the production of energy for exports, operations that currently represent the largest source of GHG emissions.

While we discuss transformations to the energy production profile in the next chapter, we focus here on the sector's energy use. Two categories of energy use must be taken into consideration in energy production activities: 1) energy consumed by energy production operations, such as fuel used to power machinery in energy resource extraction sites or electricity to power CCS operations in natural gas-fired power plants equipped with CCS; and 2) energy lost in transformations, such as heat dissipated from coal-fired electricity generation.

Optimized net-zero trajectories entail a move away from export-oriented fossil fuels production, which results in less energy consumption in the energy production sector.

Figure 2.14 shows final energy consumption by energy production facilities. The contrast between NZ50 and REF is marked even by 2030: as oil and gas production is reduced and many energy production operations are electrified (Figure 2.15), final energy consumption in the sector drops 27.0% by 2030 and 80.4% by 2050 in NZ50, compared with virtually no change over the entire period in REF.

In a net-zero scenario therefore we can assume that a much smaller quantity would be required to power operations enabling the supply of the mix, even while this mix keeps pace with population growth. In fact, today the share of energy consumed in the energy production sector of total final consumption in all sectors is 25.1%. In REF, this share remains at 24.3% of total final consumption in 2050, while in NZ50 it drops to a mere 6.7%.

Figure 2.14 – Energy consumption in energy production operations

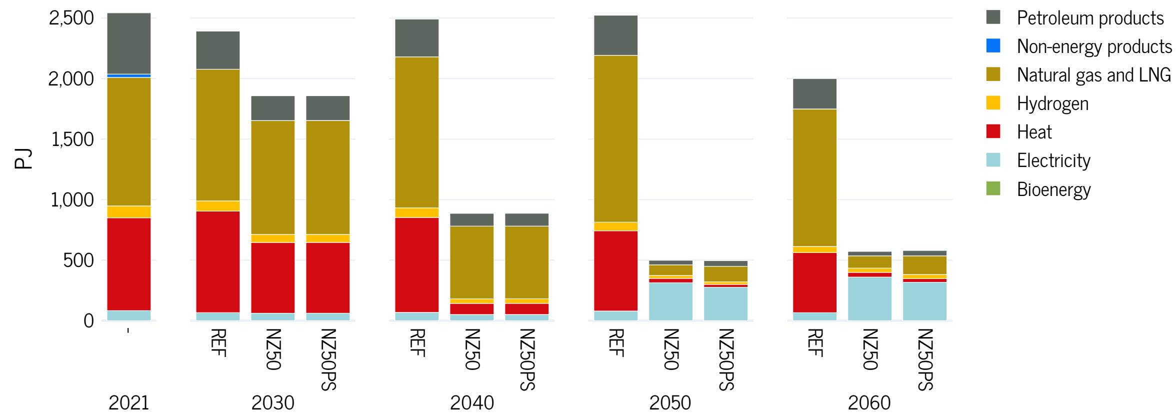
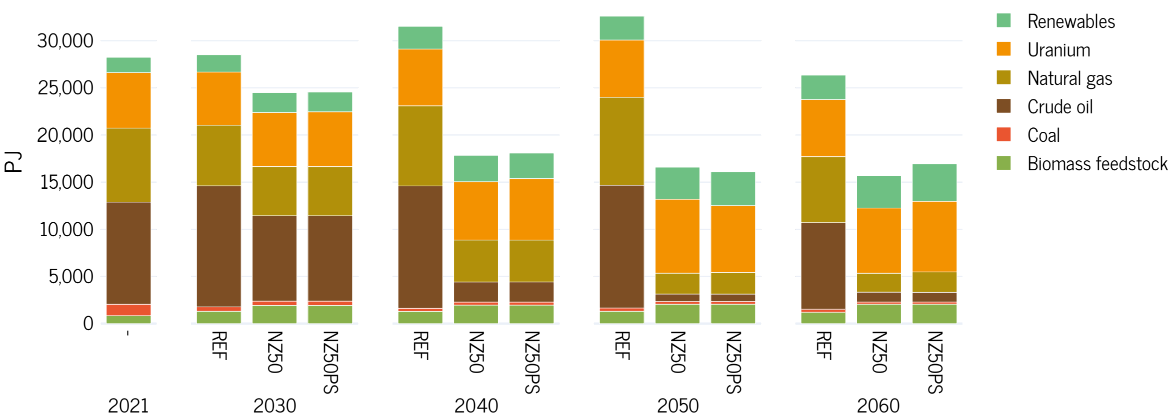


Figure 2.15 – Primary energy production



A transformation of the energy mix involves more efficient use of energy, resulting in considerable reductions in losses due to upstream energy conversion.

In terms of the transformations required to obtain an energy mix enabling the net-zero trajectory, the losses in energy production also decrease substantially. In the energy production sector, energy losses overwhelmingly occur in the use of thermal energy sources to produce energy carriers. For instance, for uranium used in conventional nuclear power production, the heat loss amounts to 68% of the energy content of the resource. In net-zero scenarios, a small part of this is reduced by the use of heat trapping technologies to power district heating. Similar losses occur for natural gas-fired electricity production, making this particular form of energy production less efficient than heat production applications using natural gas.

The implication is that not only is energy production from uranium and fossil fuels less efficient in its conversion, but this lower efficiency is also associated with a resource depletion, since these are non-renewable resources. However, when converting hydraulic or wind force to electricity, the resource is completely renewable, making the efficiency limits relevant only for land use.

In total, this type of energy loss across the entire system in the conversion to secondary energy forms is far from negligible. Therefore, it appears that a net-zero energy mix is associated with a more efficient set of transformations as well as much smaller consumption needs in the energy production sector itself, in addition to the efficiency gains throughout consumption in other sectors—for instance, through the electrification of services like transport.

To maximize this gain in energy productivity, net-zero strategies should avoid carbon capture applications whenever possible, given the additional energy needs they create.

There is, however, an important caveat to the above: in net-zero scenarios, even though energy production may become more efficient, part of this gain is offset by the need for energy to power carbon capture and sequestration installations, both in industrial CCS and BECCS applications, as well as in direct air capture (see 2.2.4). For direct air capture alone in NZ50 (Figure 2.2), close to 87 TWh (313 PJ) of electricity is needed to power the installations in 2060. In comparison, this is well above the equivalent of the entire electricity production in British Columbia (62 TWh). Therefore, reaching net-zero should imply minimization of the need for carbon capture, negative emission technologies and direct air capture.

General observations:

- The decarbonization of the energy mix and energy production activities in net-zero scenarios are associated with a higher efficiency for the sector, resulting in smaller energy losses in the supply mix.
- However, the need for direct action on capturing emissions in NZ50 requires considerable power, compensating a significant part of the efficiency gain in energy production.

2.4 Takeaways

The evolution of the mix for final energy consumption shows electricity becoming the dominant source after 2030 in all net-zero scenarios, taking shares from natural gas and oil products. The growth of electricity is also important in REF, driven by the transformation of transport services. **Current decarbonization policies are driving a large part of these expected transformations and will result in important reductions in emissions if fully implemented. However, the electrification of services in REF remains more limited than in NZ50, highlighting the limits of current policy measures and their importance in initiating and driving the transformation**.

While natural gas comes to replace other less efficient fossil fuels in the net-zero scenarios, **a substantial decline of natural gas occurs—even before 2030—highlighting the incompatibility of the fuel as a transition energy source in pathways to reach neutral emissions by mid-century** or even simply to decrease emissions.

The role of other sources like hydrogen and bioenergy is more complex: hydrogen becomes more important in NZ50 than in REF, primarily because of its use as a replacement of natural gas in industry after 2040. However, bioenergy use increases more aggressively and very rapidly in NZ50 before reaching a plateau. Its use changes over time as well: on the longer term, the possibility of obtaining negative emissions from BECCS processes means that bioenergy plays an important but different role in the mix. As discussed in Box 2.1, many uncertainties remain in the assessment of these sources' potential role in net-zero trajectories.

The pace of some of the transformations suggested by the results raises important questions. Notably, the size of the additional infrastructure needed to supply and distribute the energy mix in the net-zero trajectory is very substantial, raising key questions about labour needs, financing, and ensuring access to stable and able supply chains. Moreover, **careful planning of the strategies to ensure that this infrastructure is built ahead of increases in demand implies making choices about how to build out this new capacity**. For instance, the results discussed above show an abrupt increase in electricity and–to a lesser extent–hydrogen demand after 2040, even though in practice, it may be more practical and wiser not to rely on a massive acceleration of the build out only after 2040. This is especially true given that this abrupt increase does not end in 2050 but significantly continues until 2060.

Policies should aggressively target sectors where dominant sources to come are already known and where technological uncertainties are the fewest. For instance, this is the case for the buildings sector, where the role of heat pumps in residential dwellings and electric systems in commercial space is similar across all scenarios, replacing natural gas. It thus seems a safe bet to encourage the rapid adoption of these technologies at little risk and reasonable cost. A similar case can be made for the decarbonization of energy use in the agriculture sector.

Other sectors are much more difficult to decarbonize because of higher costs and the difficulty of substituting low-carbon technologies for other sources in some applications. Heavy commercial transport is one such case since the transformation is slow and more technologically eclectic. **Given the sluggish evolution toward a varied technology mix in this sector, different technologies are likely to be competitive alternatives to meet demand for this sub-sector. Accordingly, choices will likely need to be made about which path to favour and encourage**.

2.5 References

Langlois-Bertrand, S., K. Vaillancourt, O. Bahn, L. Beaumier, N. Mousseau. 2021. *Canadian Energy Outlook*. Institut de l'énergie Trottier and e3Hub https://iet.polymtl.ca/energy-outlook/

3

Transforming energy production in net-zero pathways

Although Canada is a major energy producer and exporter, most of these activities are associated with significant quantities of GHG emissions. As a result, the country's energy production will be deeply affected both by changes in demand and by imposed constraints on GHG emissions. These changes and impacts will differ from one province to the other, in correlation with resource distribution, availability, and the evolution of the import/export market, which is particularly important as more than half of Canada's primary energy production is destined for export. This chapter focuses on the evolution of primary and secondary energy production for the country as a whole.

Highlights

- Energy production is significantly and rapidly transformed in net-zero scenarios.
- All net-zero scenarios require an accelerated transformation of the economy away from the fossil fuel industry, even before 2030; not doing so will require more difficult and faster emissions cuts elsewhere, as well as ever-larger emission capture quantities to reach net-zero, making these paths more costly.
- The reference scenario presents a sizeable additional need for electricity to supply services across sectors, as a result of the measures implemented or developed since 2021, notably the zero-emission vehicle (ZEV) mandate and the Clean Electricity Regulations (CER).
- The expansion of electricity needs is even more dramatic in net-zero scenarios, presenting a wide gap with the reference scenario, while also illustrating the necessity of meeting short- to medium-term challenges in implementation (see Box 3.1).
- Bioenergy production expands on the short term to help meet the 2030 target in net-zero scenarios, including with negative emissions. However, the destination of the resources is modified in important ways after 2030 as different constraints lead to an optimization of biomass' contribution in the net-zero pathway.
- While hydrogen production increases to reach sizeable levels in the reference scenario, the technology mix needed to produce it and its destination outside Canada's borders make the scenario drastically different from hydrogen produced and used in NZ50.
- Current cost projections make CCS applications in oil and gas production marginal in the results.

3.1 Fossil fuels and uranium production

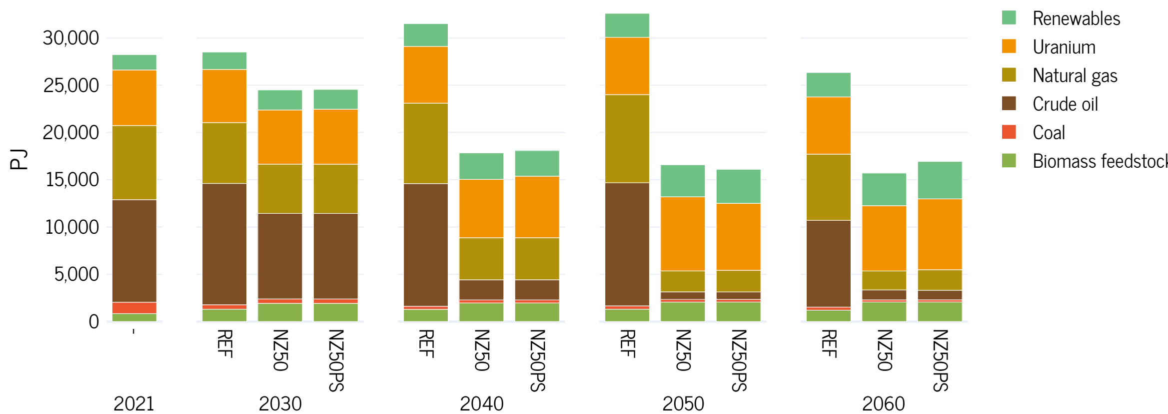
Figure 3.1 shows how Canadian primary energy production evolves in the reference and net-zero scenarios. It is worth recalling that all scenarios assume that the rest of the world will move at its own pace, irrespective of Canada's GHG targets. However, assumptions for oil and gas prices on the global market in REF are based on the Benchmark prices of the Canada Energy Regulator's Current Policies scenario, while assumptions in net-zero scenarios use those in its Global Net-Zero scenario instead, reflecting a certain degree of climate action around the world. In any case, it is likely that Canada will act on its targets only if the rest of the world shows clear leadership, directly affecting energy prices on the global market.

> **Crude oil production declines sharply in NZ50 to reach only a fraction of current levels, in complete contrast to REF.**

In respect of crude oil production, the contrast between REF and NZ50 appears very early on. Production in REF shoots up 18%, from 10,840 to 12,830 PJ, by 2030, before remaining at a similar level until 2050. A sharp decline to 9,180 PJ then occurs before 2060, reflecting current understandings of the long-term trends in export markets.

In NZ50, production drops 16% by 2030 before then abruptly decreasing to 20% of 2021 levels by 2040. By 2050, crude oil production is down 93% from today's levels, to 1,050 PJ, reflecting the lower cost of acting decisively on this particular production for the country to reach the net-zero point. To be clear, this decrease is not triggered because of the downstream emissions from this production, which represent between 70% and 80% of life-cycle emissions from these barrels, as only emissions within Canada's borders are accounted for here, following the Paris Agreement's production approach to emissions accounting.

Figure 3.1 – Primary energy production



Hindsight in energy outlooks: focus on energy production

In contrast to consumption projections (see Chapter 2), production outlooks from the scenarios considered here and corresponding results from the previous edition of the Canadian Energy Outlook (CEO2021) yield mainly similarities (Langlois-Bertrand *et al.* 2021). Nonetheless, certain exceptions need to be highlighted.

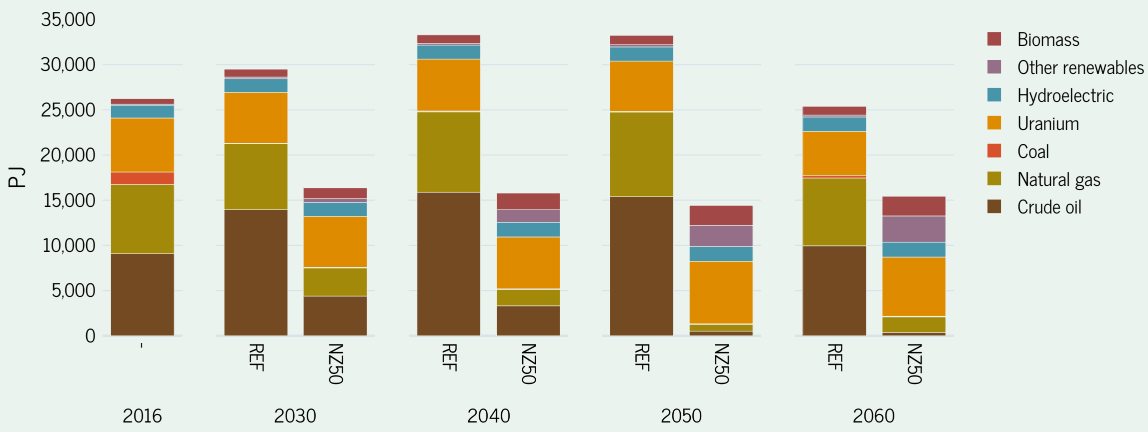
In terms of fossil fuels production, both CEO2021 and today's net-zero scenarios illustrate the high overall cost of maintaining high crude oil and natural production levels while reaching the net-zero target in 2050. The political constraints tied to realizing such reductions should certainly lead to a careful reading of these results, especially in light of the geographic concentration of some of these activities in communities that would be directly affected by a move away from this production (see Chapter 4 in Langlois-Bertrand and Mousseau 2024).

Nevertheless, the need to compensate the choice to maintain higher production levels to protect the sector leads to a greater cost to the system since emissions must be reduced in more costly transformations in other sectors, short of reducing agriculture or outputs in other industries.

Another similarity with the CEO2021 is the dramatic expansion in electricity production in net-zero scenarios and the challenges associated with its implementation. In the CEO2021, electricity production in the NZ50 scenario increased to 4,800 PJ (1,330 TWh) by 2050, compared to 4,600 PJ (1,280 TWh) in the main net-zero scenario used in this report. While better information is now available to assess the cost of some technologies in this mix, including nuclear small modular reactors (SMRs), challenges remain as to how to plan and act on deployment of the quantities suggested by the results.

Similarly to the CEO2021 as well, the reference scenario also projects significant increases in electricity demand, even if NZ50 levels are much greater. These levels are similar today (3,000 PJ or 850 TWh)) compared to the REF scenario in 2021. This is the result, in part at least, of more cost-effective production technologies that push electrification in some applications.

Figure 3.2 – CEO2021 primary energy production



Therefore, reference scenarios across both 2021 and 2024 show that needs for electricity will expand significantly, even in the absence of additional measures to decarbonize. This provides an opportunity to think about planning deployment, not only in terms of net-zero pathways, but also in terms of the transformations already taking place before the exact form of future policy measures is known.

Natural gas production is more affected by domestic demand drivers than crude oil, but a rapid gap also emerges between NZ50 and REF.

The evolution in the production of natural gas also presents a sharp contrast between REF and NZ50, albeit to a lesser extent than for crude oil. By 2030, natural gas production, which reaches 7,840 PJ today, declines 18% in REF, while the decrease is more rapid in NZ50 (-34%).

After 2030, the contrast is much steeper: REF sees natural gas production increase significantly, rising 19% in 2050 (9,320 PJ) as compared to today. In NZ50, the period after 2030 does not see a rebound and natural gas production is down to 22% of today's levels in 2050 (2,210 PJ).

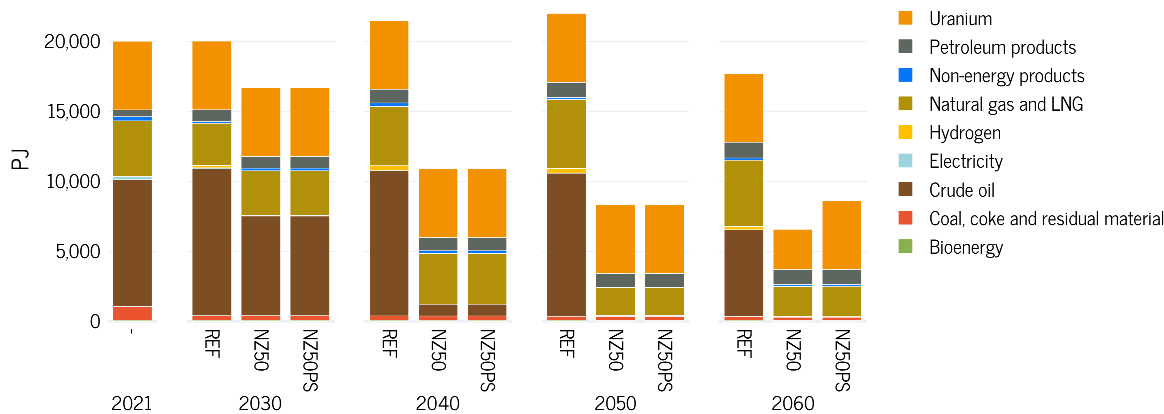
Since the model does not include any new liquefied natural gas export facilities, the drivers of this evolution in natural gas production levels are mainly domestic, contrary to the case of crude oil. In fact, crude oil exports (Figure 3.3) drive most oil production levels in REF, while NZ50 imposes a production cut to limit the emissions associated with production. In the latter scenario, oil consumption decreases at the national level. However, since it starts with a much smaller share of the destination for crude oil production in the first place, the reduction in exports dominates overall production cuts.

In the case of natural gas, production-related emissions are reduced due to the constraints imposed by the regulation on fugitive emissions. Export levels therefore decline, although less significantly than for oil, with 2050 exports still at 50% of current levels in NZ50, from 3,760 to 1,980 PJ between today and 2050. The rest of the decrease in natural gas production thus derives from a reduction in domestic consumption (see Chapter 2).

The production of refined petroleum products mainly follows domestic consumption in each scenario, although exports increase.

In REF, the quantity of oil products from Canadian refineries increases over time at a pace similar to consumption. However, exports double by 2040 and continue to increase, reflecting trends in regional markets. NZ50 also sees a doubling of exports, although overall production decreases after 2030. By 2050, refined petroleum products from refineries are 23% less than today's levels (2,800).

Figure 3.3 – International energy exports



Uranium production increases, driven by domestic demand in new nuclear electricity capacity, while exports remain at similar levels throughout 2060.

Owing in part to its small GHG footprint, uranium production increases to meet the larger domestic needs for nuclear electricity production in net-zero scenarios, while maintaining current export levels throughout the period. In REF, export levels are also maintained, but domestic consumption does not increase, with the result that production remains more or less stable throughout 2060.

In particular, the role of small modular reactors is more modest in REF than in net-zero scenarios, reflecting cost expectations in the absence of stronger electrification incentives (see Section 3.2). Nevertheless, detailed projections on future exports markets for uranium are limited and, as a result, the assumption that current export levels will stay constant remains uncertain.

Coal production declines rapidly, reflecting both domestic constraints on its use and the shrinking regional market for the fuel.

Finally, reductions in coal production are driven by economic considerations and a shrinking market due to regulations like the coal phase-out in electricity production – as well as the upcoming Clean Electricity Regulations – and to carbon pricing in general. Levels follow a similar path in both REF and net-zero scenarios. Production decreases by 61% in REF and NZ50 by 2030, before declining less steeply over the rest of the horizon.

Overall, fossil fuels production is deeply affected by the net-zero constraint, even if emissions at the consumption stage in export markets are not accounted for in the modelling.

More than half of fossil fuels produced in Canada are burned outside of its borders. Nevertheless, the emissions associated with the production activities are strongly targeted by the net-zero scenarios, making production cuts one of the most cost-effective ways to reach the 2050 target.

General observations:

- NZ50 production levels for fossil fuels decline sharply, suggesting a lower direct cost per tonne of emissions avoided compared with many other reduction options throughout the economy.
- The evolution of this production in REF is largely driven by world markets, which may evolve very differently from assumptions as a function of the production in other countries and the level of efforts to decarbonize the worldwide economy.
- While production cuts in NZ50 may involve costs well beyond the energy system, opting to maintain higher levels of oil and gas exports imposes more rapid and deeper reductions in Canada's consumption of oil and gas products in almost all sectors to reach the same GHG reduction targets.
- Levels of oil production for export markets in NZ50 are closely tied to the cost of carbon capture and sequestration (CCS); while current cost projections make CCS applications in oil production marginal in the results, should this cost fall, more production could be maintained on an optimal path to net-zero. CCS is discussed in more detail in Chapter 4.
- Similarly, while natural gas does not appear as a transition fuel for Canada in our modelling, its continuous use worldwide to displace coal or as a feedstock for producing hydrogen, in conjunction with low-cost effective CCS, could lead to a major increase in demand for Canadian gas on both internal and external markets.

3.2 Electricity generation and installed capacity

As detailed in Chapter 2, electricity plays a central role in the decarbonization pathways, increasing from its current share of 24% of final Canadian consumption to between 52% and 54% in 2050 and 2060 for the net-zero scenarios. Given the very limited amount of imports from the U.S., this electricity is produced overwhelmingly from provincial grids for the entire time horizon.

Electricity production increases considerably even in REF, following expected growth in demand.

Electricity demand increases considerably even in the reference scenario, growing 12.2% before 2030. Production growth over the same period is relatively modest (4.6%), as part of the demand is met by reduced exports. By 2050, production levels are 28% higher than those of today in REF (830 TWh), following an increased population and expected transformations driven by current trends and policy measures. In particular, regulations to accelerate the electrification of light-duty transport play a large role in boosting demand.

Given the central role of electricity in net-zero trajectories, production drastically increases to meet the needs imposed by the transition and growth accelerates over time.

In the net-zero scenarios, the massive electrification of energy services in all sectors requires a twofold increase in production capacity by 2050 (in order to produce 1,280 TWh). NZ50 also shows that this growth accelerates considerably over time: by 2030, production levels follow a curve similar to REF, with a 4.6% increase. This underlines similarities in the drivers of electrification on the very short term for both REF and NZ50, largely imposed by regulation, notably in light-duty transport.

Other transformations take more time, only kicking off in the 2030s. As a result, production grows almost 30% between 2030 and 2040 in NZ50, and then a further 47% between 2040 and 2050. This reflects the relatively high cost of electrification in sectors where policy measures have yet to clearly constrain and orient transformations. Electrification in these sectors is therefore delayed in the model until it becomes necessary to reach the 2050 GHG reduction target.

Maintaining net-zero emissions past 2050 requires further buildout of electricity capacity as energy demand continues to grow given more limited possibilities for further transformations and efficiency improvements. By 2060, production reaches 1,490 TWh (5,350 PJ).

Figure 3.4 – Electricity production by technology

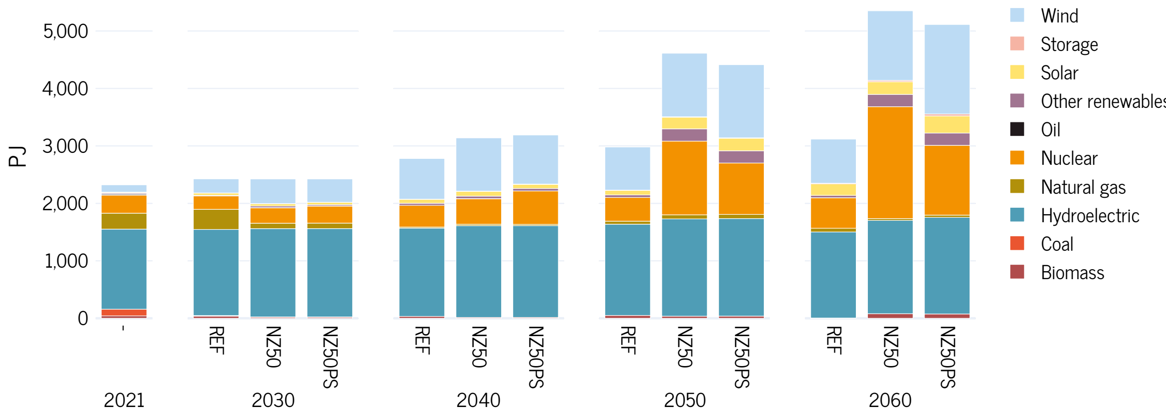
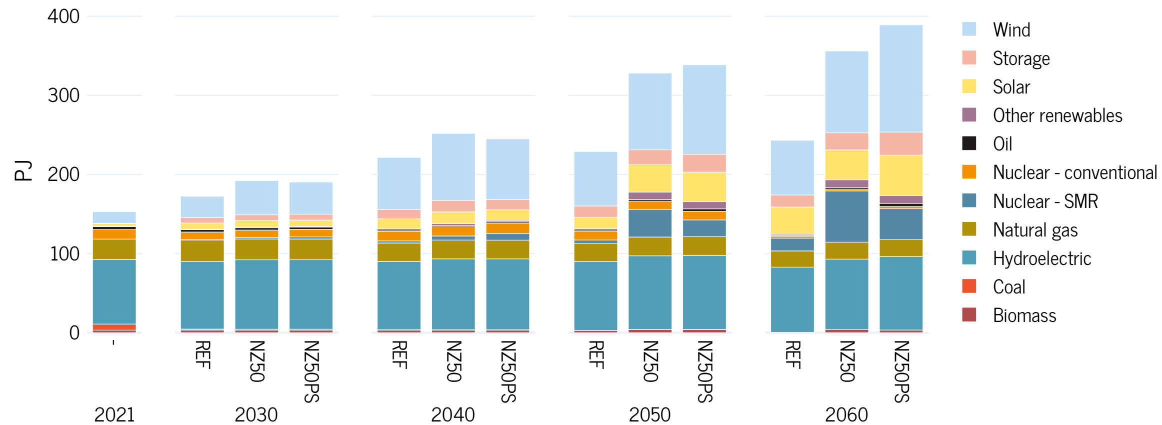


Figure 3.5 – Electricity capacity by technology



Despite a significant difference in total output, the technology mix is relatively similar in REF and NZ50.

Cost projections for the dominant electricity generation technologies foreseen to play a role in the near to distant future make the distribution of the capacity mix evolve similarly in REF and NZ50, the difference being in the scale of deployment. For instance, onshore winds see the fastest growth from today to the 2040s, and the share of centralized solar in the mix is nearly identical in REF and NZ50 in 2030 and 2040. Decentralized solar quantities are even identical across scenarios in absolute terms throughout the entire horizon.

These similarities continue through 2060. This growth in variable generation sources also causes storage to grow in similar proportions. Therefore, what distinguishes net-zero scenarios from the reference scenario is first and foremost the sheer quantity of electricity needed to support the decarbonization of the economy.

Conventional nuclear evolves similarly in all scenarios, reflecting projected cost advantages of small modular reactors (SMRs).

With current cost projections, conventional nuclear facilities evolve similarly in REF and net-zero scenarios until they are retired at end of life, with additional capacity added in the 2030s only in Ontario. The key difference across scenarios in terms of nuclear generation is therefore the extent of SMR deployment, which is assumed to be at lower cost for the additional quantities needed by NZ50.

SMRs grow to become the largest source of production in NZ50, outpacing the growth of technologies associated with lower capacity factors.

The same baseload sources emerge as key balancing factors to help reduce the need for longer-term storage, including first and foremost nuclear SMRs. In the main net-zero scenario, SMRs quickly grow after 2040 to become the chief baseload source. Given their high-capacity factor compared with variable generation, in NZ50, capacity installed for SMRs reaches 10% of the capacity mix by 2050 (from less than 2% in 2040), which corresponds to 22% of all electricity produced (280 TWh). The added benefit of waste heat recovery from SMR electricity generation also helps reduce the cost on an energy basis.

The impact of SMRs on the longer term is even greater and not limited to NZ50. In 2060, the share of electricity production from SMRs grows to 35% of the total in NZ50 (520 out of 1,490 TWh), becoming the largest source of electricity for the country as a whole. In REF, the high cost projected for SMRs leads to a smaller buildout, resulting in 4.5% of the total in 2050. Nevertheless, this continues to grow rapidly, and SMRs reach a 15% share of total production in 2060.

SMRs remain sensitive to costs and more pessimistic assumptions result in smaller deployment, which is compensated by growth elsewhere in the mix.

While NZ50 uses relatively conservative assumptions for SMR cost decreases, the results raise questions about how to treat both technological and economic uncertainties for a technology that is not yet available but could become the largest source of electricity in the projected future. While in NZ50, projections see SMR costs decline 23% from now to 2050, we also use an alternative net-zero scenario which takes a more pessimistic outlook and assumes no cost reductions over time for SMRs (NZ50PS).

The impact of this changed assumption is important: in NZ50PS, total electricity production and consumption remain virtually the same as in NZ50 across the entire time horizon. However, the capacity mix evolves very differently: the reliance on dominant variable generation technologies becomes greater because of cost. This however requires a much more massive buildout due to lower capacity factors. On-shore wind capacity in particular is 17% higher than in NZ50 by 2050, and 31% higher in 2060. Similarly, centralized solar capacity is almost 50% higher by 2060 in the NZ50PS scenario.

The need to compensate for the smaller SMR baseload in NZ50PS also increases the reliance on storage, with 33% more capacity from batteries in 2060 and 50% more from pumped hydro facilities. Importantly, this occurs even with what remains an important buildout of SMRs: despite higher costs, SMR electricity production reaches 14% of the total in 2050 and 22% in 2060 in NZ50PS.

The future of SMRs is clouded with uncertainties extending well beyond costs, but the results for NZ50PS provide a picture of the impacts of any limitation on deployment.

Given the differences in the results for NZ50PS and NZ50, two important observations arise. First, the evolution of costs for SMR vs. centralised and distributed storage technologies will be a key factor impacting adoption. Given the stage of deployment, which has yet to reach commercial scale anywhere in the world, uncertainties in terms of not only cost but also construction delays mean the results should be treated with care (in both net-zero scenarios shown here and the reference scenario).

The second observation is that the non-cost factors like social acceptability could act as a similar break on the perspectives for deployment, requiring other sources to fill the gap. While some provinces have committed to SMR deployment, most have not. Therefore, assuming that it would be possible to obtain social acceptability for SMR construction simply because the need arises is certainly problematic. Instead, at the very least, we should expect delays in deployment to be increased by these factors.

Putting these two observations together, we can assume that the alternative net-zero scenario can be understood simply as a future where there is less SMR generation, regardless of the exact causes of this more modest buildout. This assumption can help inform reflection on how to treat this generation option and, as a result, alternatives to it.

Due to higher costs, geothermal emerges in net-zero scenarios and only barely in REF.

Geothermal electricity generation grows very modestly in both REF and NZ50 until 2040, where it takes off only in the net-zero pathway. In 2050, the share of electricity produced by geothermal increases in NZ50 to 4.6% of the total (60 TWh).

The contribution of biomass to the mix is closely linked to the need for negative emissions.

With 1.5% of production, wood-based generation comprises a small share of the total today. In REF, the levels remain relatively constant throughout 2050, but in NZ50 this production is largely converted to BECCS facilities, contributing to negative emissions. This change only occurs after 2040 however, reflecting the high cost of this production. The growth continues to 2060, as more negative emissions are needed to maintain the net-zero equilibrium.[1]

Natural gas with CCS does not emerge as a key source despite the impact of the CER.

As the Clean Electricity Regulations (CER) kick in, natural gas-fired generation decreases drastically in both REF and NZ50. In the case of NZ50, this drop precedes the 2035 date for the achievement of net-zero electricity production: this type of generation is already down 69% from current levels in 2030 and virtually disappears after 2035. The short-term contrast with REF is quite sharp, as natural gas-fired generation is up 23% in 2030 in REF, before declining 97% between 2030 and 2040 as a direct result of the CER.

The high cost of CCS-equipped facilities, combined with the smaller overall growth in electricity consumption, makes natural gas with CCS production marginal in REF. In NZ50, the emergence of this production is more significant after 2040, but the high costs limit it ultimately to a 1.5% share of the total in 2050, without further growth.

Dominant baseload production could take very different forms depending on a host of factors outside of costs, such as social acceptability, additional technological developments in storage, and adoption and market development elsewhere in the world.

The need to expand production capacity to the extent suggested by net-zero scenarios raises important questions about additional baseload options. On the one hand, renewables like onshore wind and solar are the cheapest technologies both today and in the near to medium-term future. However, their rapid growth poses challenges for their integration into a resilient grid, given their variable production. While grid optimization and more sophisticated distribution management can go a long way in tempering these challenges, the amounts of variable generation presented in the results also require a large quantity of additional stabilizing production, either from baseload generation or from storage.

On the other hand, cost is far from the only factor to consider in assessing potential for the future generation mix in this respect. With relatively smaller thermal powerplants being excluded after 2035 due to the CER, baseload options could include significant additions to the capacity of the hydropower fleet, for instance, even if costs may be higher on a per kW basis.

Perhaps more importantly, cost estimates are to be treated with care for each of these options. Few large hydroelectric facilities have been built over the past two decades, making information scarce on the evolution of their cost, despite significant remaining theoretical potential across the country. The existing nuclear fleet would require costly investments to use past the 2040s and the first SMR has yet to be built and made operational to confirm cost projections. In each of these cases, additional infrastructures in these categories largely lack social acceptability, which implies that a significant buildout will be influenced by lengthy public debate over the merits and risks of each, making cost only one of the major uncertainties about their deployment. Although more attention is currently being directed toward geothermal potential than in the past, the lack of experience with the technology in Canada keeps costs high for now.

[1] See Chapter 4 for a discussion of negative emissions' role in net-zero pathways.

Large-scale storage, especially storage that would last for more than a few hours or could be used for long-term planning, also remains too expensive based on current projections to be able to displace a large part of the need for additional baseload. This could change drastically in the future, depending on technological developments and adoption and market development elsewhere in the world, helping to shape the outcome of debates over baseload.

> **Interprovincial exchanges could play an important role in helping balance the grid with smaller quantities of additional generation, although this would require a transformation in prevailing provincial hesitations.**

The model used here considers additional interprovincial exchanges, but with important limitations in relation to peak demand. Therefore, additional contributions from interprovincial exchanges, notably to help manage temporary drops in variable generation output, could be more important than the above results suggest.

One important constraint on such exchanges is the existence of regional reference reserve margins, imposed by the North American Electricity Reliability Corporation (NERC) due to the cross-border interconnections. A sensitivity analysis, available through the Pathways Explorer,[2] was conducted to determine whether abolishing this requirement would result in much greater interprovincial trade in a net-zero scenario. Results showed only marginal changes as long as peak demand must be met provincially.

In any case, expanding this trade and making provincial grids more interdependent with new lines requires political will and social acceptability, similarly to the baseload considerations discussed above. Cost considerations are only one part of this puzzle, and discussions over adding additional interprovincial electricity trade capacity will have to be based on choices made in the planning of the grid of the future to identify areas where contributions could be the most cost effective.

Box 3.1 – Challenges and barriers in developing electricity grids for a net-zero society

The expansion of electricity's contribution to the energy mix in net-zero scenarios is substantial, with a doubling of current levels needed to support the delivery of energy services in 2050 in NZ50. While discussing the options for the composition of the additional capacity is important, focusing on the overall increase obscures additional difficulties inherent in this deployment. In other words, the results presented in this chapter do not fully point out the barriers and difficulties to deployment. A brief look at these impediments is thus provided below.

The exacerbation of peak demand

A first challenge lies in the management of peak demand in the planning. The extent of the electrification suggested by the results exacerbates already substantial pressures on the grid's capacity in peak periods, especially as the electrification of buildings will increase the likelihood of yearly peaks being simultaneous across regions and provinces in the coldest days of the winter. Moreover, this type of peak cannot be addressed simply by demand displacement, but will require instead much more active demand management.

Storage, baseload and variable generation integration

Another challenge follows from the integration of substantial additional capacity from variable generation sources. Given cost considerations alone, a very large part of the capacity increase will come from wind and solar, which requires careful attention for the balancing of the load to meet demand at all times.

While technological innovation like digitalization will reduce the severity of this challenge, choices will need to be made regarding baseload expansion, and options are more limited given the need to keep generation as close to zero-emission as possible. The pace of the development and cost reductions of nuclear SMRs, and the tapping into additional hydropower potential, will be considered in the face of important concerns like social acceptability. While the contribution of storage options remains limited in the results presented in this chapter, technological innovation could change perspectives, especially for long-term storage.

Improvements in grid resilience

The importance of grid resilience will increase as electrification expands and the list of services provided by electricity becomes more extensive. In particular, since a very large part of transport and heating is considered essential, blackouts and other disruptions will need to be both rarer and shorter. To achieve this requires improving resilience planning in the management of grids, especially given the impacts from more frequent extreme weather events caused by climate change.

Supply chain constraints

Canada is not the only country where strong pressure is being exerted to electrify services. Many other parts of the world are following a similar path, and most are also actively considering an intensification of this effort to set themselves on a net-zero trajectory. As a result, supply chains are likely to become more strained at various times over the next years and decades, raising costs and complicating the supply of the technological components required to pursue the grid expansion discussed here.

The combination of these challenges highlights the need for careful planning of grid expansion and improvement, starting with detailed integrated resource plans developed across the provinces.

[2] See scenario M8 in the Pathways Explorer.

Electricity buildout to match demand projections highlights the urgent need to solve implementation challenges and the status quo will be insufficient to meet future needs.

Demand projections for electricity clearly show that significant new infrastructure will be needed to increase generation capacity, improve load management and demand response, and upgrade distribution grids to match changing demand profiles that evolve with the electrification of many services previously supplied by other sources of energy. Meeting these challenges is already necessary in a world where current ambitions to achieve net-zero emissions are not being met. Upgrading electricity infrastructure to the levels suggested by the net-zero scenarios therefore requires planning to be urgently adapted to resolve or address implementation challenges (see Box 3.1), including the development of a clear vision toward 2050.

General observations:

- Electricity production expands in REF as a result of growing demand and the electrification of services like personal transport. These levels are significantly surpassed in the net-zero trajectories, where the needs to support the electrification of a long list of services across sectors lead to a doubling of electricity's share of total final energy consumption.
- Cost considerations mean that accommodating such increases requires a deployment of considerable wind and solar production capacity, which also creates needs for balancing variable generation with additional baseload capacity and storage.
- In all scenarios, although nuclear SMRs play an important role in providing this baseload, social acceptability and technological and economic uncertainty require a careful treatment of this result. In any event, other stabilizing sources, if not nuclear, also bring uncertainties and will require public debate and political choices well beyond cost.
- While electricity needs are substantial in all scenarios, these are certainly an understatement of the real demand in the future, as these results come from an optimal application of electrification across sectors, which in practice is never fully accomplished.

3.3 Bioenergy

Primary biomass production increases rapidly to match growing demand needs on the short term.

Even though its share of total primary production is smaller than fossil fuels, biomass feedstock production increases rapidly in all scenarios. REF results in a 55.6% increase over current levels by 2030 (1,310 PJ), while in NZ50 levels more than double by 2030 (1,930 PJ). The overwhelming share of biomass is used domestically due to growing consumption levels as discussed in Chapter 2, especially in net-zero scenarios where it helps achieve short-term reductions to meet the 2030 GHG emissions target.

Following consumption levels, biomass production remains at similar levels after 2030 in all scenarios, occupying a much larger share of primary energy production in net-zero scenarios.

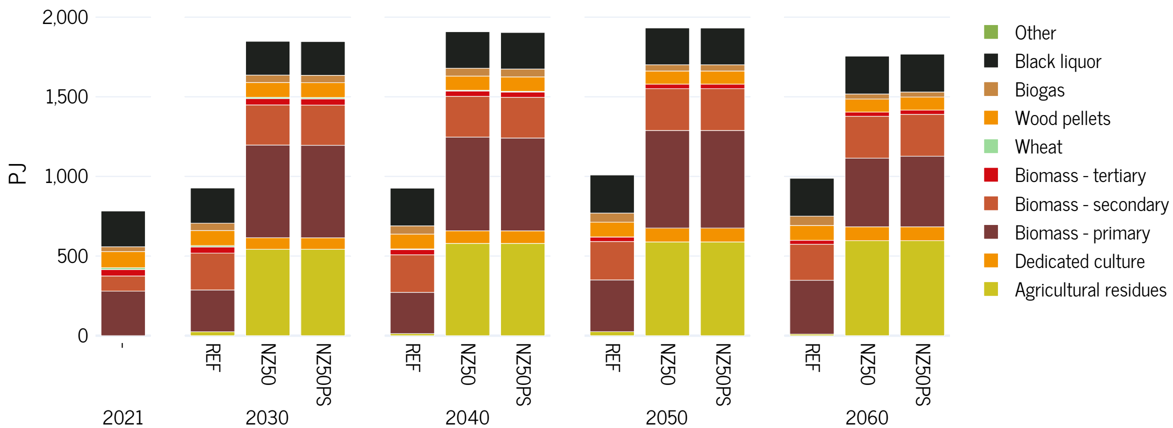
After 2030, levels in both the reference and the net-zero scenarios remain constant for the rest of the horizon. In NZ50, the initial increase prior to 2030, combined with the reduction in oil and natural gas production, raises biomass feedstock production to 12% of total primary energy production in 2050 (2,060 PJ), up from 3% today. The picture is different in REF, where this share is only 4% in 2050 (1,300 PJ) due to the much larger remaining oil and gas production.

Agricultural residues and wood escalate rapidly in NZ50, helping supply low-emissions sources to meet the 2030 GHG reduction target but stalling afterward.

The mix of biomass feedstock used differs sharply among scenarios along this evolution. Before 2030, the rapid overall increase in NZ50 results in large part from agricultural residues, growing from virtually nothing today to 28% of the biomass mix 2030 in NZ50, while barely increasing in REF.

These additional quantities are used in NZ50 for their contribution to the 2030 reduction target, as agricultural residues are used mainly to produce syngas that is destined primarily for buildings. In the process, biochar is obtained, resulting in a significant quantity of negative emissions (44 $MtCO_2e$, including through the contribution of wood biomass). However, after 2030 growth comes to a halt due to feedstock availability.

Figure 3.6 – Feedstock used in biomass production



Wood biomass expands in all forms in REF, but nowhere close to NZ50 expansions.

Another important change on the short term is the growth in primary and secondary forms of wood biomass. In REF, only secondary wood biomass (residues from wood transformations as in the pulp and paper industry) increases on the short term (+142% by 2030). Quantities of this feedstock do not grow further in this scenario, while primary forms have to wait for the 2040s for a 16% increase over today's levels.

In NZ50 however primary wood biomass production more than doubles to 582 PJ by 2030, while remaining relatively constant until 2050. Secondary forms follow a pattern similar to REF, mainly because in NZ50, wood also becomes a more important source of syngas and biochar, both replacing higher emitting sources like natural gas in buildings and providing permanent storage for CO_2 through soil amendments (for a total of 44 $MtCO_2e$ in negative emissions, when including similar processes from agriculture residues). After 2030 however, further growth is restrained by cost and resource availability.

Current incentives and regulations surrounding biofuels lead to a large short-term increase in production, but no further growth in the absence of concrete measures past 2030.

In REF, total quantities of biofuels produced increase almost five-fold to 330 PJ in 2030. This rise is largely driven by advanced liquid biofuels, including biojet, renewable diesel, and cellulosic ethanol, largely owing to the constraints imposed by the Clean Fuel Regulations. Renewable natural gas from landfills also grows from negligible levels today to 10% of the total.

The net-zero scenario makes a more substantial use of biofuels throughout the 2050 horizon, and with a different mix of fuels, in large part to produce negative emissions with BECCS processes.

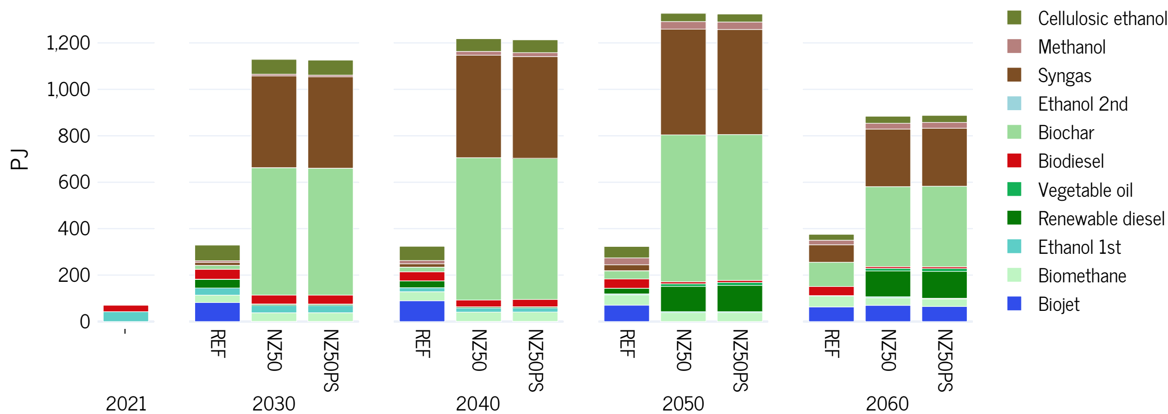
NZ50 increases biofuels production much more significantly than REF. By 2030, levels rise by a factor of 16 in comparison to today. Increases to 2040 and 2050 are more modest, adding an additional 100 PJ per decade to 1,320 PJ in 2050.

The mix of fuels produced in the net-zero scenarios is also quite different from REF. While biomethane and first and second generation ethanol follow a path mainly similar to REF, most of the increase in NZ50 comes from significantly larger quantities of biochar and syngas. In contrast, little biojet and biodiesel is produced in NZ50. This relates again to the particular role that bioenergy can play in net-zero trajectories: biochar serves as an emissions sink (with negative net emissions), helping to compensate the remaining emissions from other sources from 2030 to 2050. Moreover, syngas becomes a cost-effective choice as a source of heating for buildings and in industry because it is the main output of the biochar production process. As a result, the use of syngas across sectors in NZ50 by far surpasses that of renewable natural gas (8 to 10 times more at all times from 2030).

The mix of bioenergy production and consumption is transformed over time in NZ50 scenarios due to the contribution of bioenergy with negative emissions to meeting the net-zero constraint.

Overall, biomass expands extensively in all scenarios by 2030, primarily as a substitute for fossil fuels, either in the form of liquid biofuels (in all scenarios) or syngas (in net-zero scenarios). Overall, this expansion is even more rapid in NZ scenarios than in REF. However, results indicate very considerable differences in the biomass mix after 2030 between REF and net-zero scenarios.

Figure 3.7 – Biofuels production



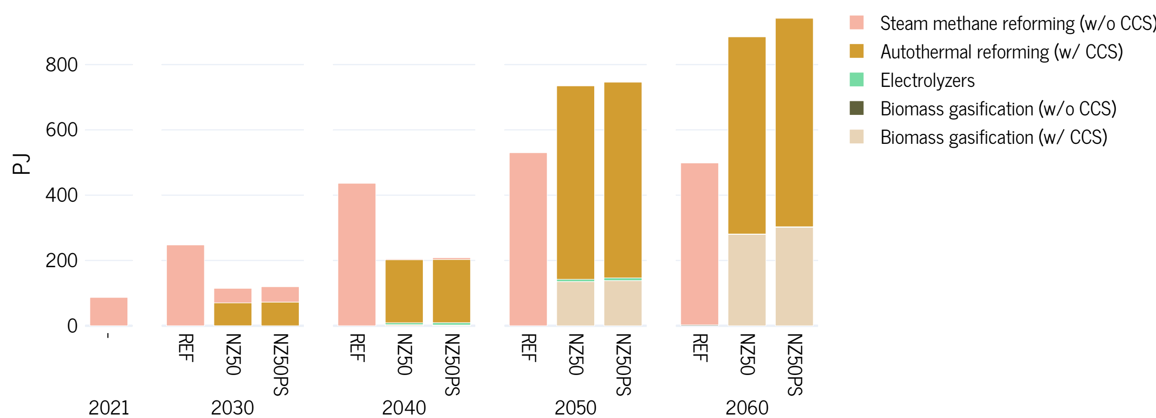
Over time, biofuels become less important than BECCS in net-zero scenarios. Syngas plays a very large role over the short term, being used in buildings and industry in 2030 and 2040 and then in energy production in 2050. However, as the net-zero point is reached and demand continues to grow, further transformations after 2050 make its use – and the corresponding negative emissions from biochar – more limited. After 2050, biomass resources are diverted to hydrogen production, which supplies the greater demand while also achieving the negative emissions.

Overall, the exact mix of bioenergy production and use is difficult to assess given the numerous uncertainties pertaining to cost-effective opportunities in using the resources, needs across sectors, as well as GHG accounting contentions associated with it (see Box 2.1). One thing is certain: these results show that bioenergy can play a particularly important role in decarbonization pathways, although maximizing this role will require a careful assessment of the merits of the different options and a proactive management of the resources.

General observation:

- Bioenergy grows in importance across all scenarios on the short term before maxing out after 2030 due to resource availability and residual emissions; the mix is however different in NZ50 than in REF, as the former uses biofuels primarily to decarbonize while waiting for other technologies like electricity to achieve cost reductions.
- The use of biomass in net-zero scenarios is closely linked to the production of negative emissions, which serve to compensate remaining emissions across the economy.

Figure 3.8 – Hydrogen production



3.4 Hydrogen

Although hydrogen production expands in all scenarios, the increase is continuous in REF, while NZ50 shows a very large expansion of production in the 2040s as we approach the net-zero point.

In REF, hydrogen production expands over the entire period. By 2030, production levels almost triple from 87 PJ today to 247 PJ in 2030. Quantities continue to increase at a similar rate to 2050, more than doubling again to 530 PJ.

In NZ50, short-term expansion in hydrogen production is more modest: 2030 sees 115 PJ produced in the country, which then increases to 205 PJ in 2040. Growth after 2040 is much more abrupt however, reaching 735 PJ by 2050 and 885 PJ in 2060, well above REF levels. As a result, hydrogen production is more important when approaching the net-zero point than in the reference scenario.

Demand drivers for this production differ significantly between REF and the net-zero scenarios.

Beyond differences in the total quantities produced on the longer term across scenarios, the drivers of this evolution are in sharp contrast in REF and NZ50. In the reference scenario, domestic consumption of hydrogen increases much more slowly than production, with most of the new production destined for export. In NZ50, hydrogen exports are nil and all production is consumed domestically.

The above illustrates how the reference scenario presents an evolution of production that is expected to match growing demand elsewhere in the world, while, in the absence of additional policy incentives, domestic transformations to increase the fuel's importance in the energy mix are too expensive outside of heavy transport. In NZ50, the net-zero constraint has needs for more hydrogen applications in industry as a cost-effective tool to help reach neutral emissions, resulting in domestic consumption of all the amount produced.

The technology mix to produce hydrogen does not change in REF, illustrating the much greater cost of blue or green hydrogen production necessary in NZ50.

In REF, all hydrogen production comes from steam methane reforming without CCS, which does not change over time in the projections. In NZ50, things are quite different, as low-emission production comes to dominate, especially after 2030. No steam methane reforming is used from 2040, and hydrogen is derived instead from CCS-equipped autothermal reforming (blue hydrogen) or from biomass gasification with CCS, a BECCS process that contributes negative emissions to the net-zero pathway.

In NZ50, green hydrogen production from electricity is negligible, although part of this is due to the possibility of producing negative emissions using the BECCS process instead. As discussed in Box 2.1, evolving accounting standards for biomass emissions may impact the assessment of this potential and, in any case, production costs for green hydrogen may largely determine the exact mix observed in the future.

3.5 Takeaways

Both the importance of the energy production sector in the Canadian economy and needs for a significant upgrade in production capacity for some sources in net-zero pathways call for careful consideration of the implications of the net-zero objective for energy production. Even more, the challenges associated with the implementation of the net-zero pathways are enormous, highlighting the urgent need for coherent and integrated planning.

At the moment, Canada is a major energy exporter (Figure 3.3), deriving substantial export revenues and employment from the large part of the energy sector that operates this export-oriented production. The transformation of world energy systems could therefore have a significant impact on this trade as most of the renewable energy that will be added over the next few decades is expected to take place at the expense of fossil fuels. As well, the rapid decrease in domestic production necessary in net-zero scenarios would affect these export levels as early as 2030.

While the REF scenario shows important transformations to be expected from measures put in place over the past few years, these changes mainly apply to energy consumption and electricity production. Fossil fuels production, which for now dwarfs renewables, remains relatively unaffected by these constraints, with the potential exception of the upcoming emissions cap for the oil and gas sector. In any case, international factors are likely to have a greater impact on Canadian production, barring other policy constraints, underlining the dependency of the Canadian energy production sector on factors well beyond its control. These factors include the potential for the rest of the world to follow a trajectory where net-zero commitments are intensified, leading to lower demand for oil and gas products.

Accordingly, the risks and social costs associated with maintaining a large fossil fuels production sector will only increase with time, particularly in oil- and gas-producing provinces. Short of such a reduction in oil and gas production levels, reaching net-zero would require choices that involve reducing agricultural production or industrial processes, in addition to even greater electrification. Nevertheless, this assessment must be carried out with care to ensure that any strategy to move away from this production can help compensate for job losses in specific regions and export revenues that will be lost in the process. In any case, this implies a diversification of the economy away from the energy production sector, as oil export revenues are unlikely to be replaced by the export of low-emission energy sources, a reality that must be faced sooner or later.

Second, **a dramatic expansion of low-emission electricity production is expected in all net-zero scenarios, a large portion of which will come from variable production technologies, requiring important choices and planning for baseload and storage expansion**. The exact role of individual baseload and storage options is difficult to determine at this point, given the size of the needs: additional hydropower facilities, nuclear SMR deployment, or large long-term storage capacity all imply significant uncertainties about costs and social acceptability. Nevertheless, the fact that provincial preferences (political and social) about these options vary does not change the list of barriers to implementation most of them face. Furthermore the options to meet these challenges are only partly alleviated in some provinces by incumbent infrastructure and renewable resources availability (Edom *et al.* 2022).

Third, although **bioenergy is expected to rapidly play an expanded role**, this role is largely tailored to maximize its contribution to negative emissions, while keeping costs in check and without impeding other low-carbon transformations across the entire time horizon. While bioenergy also contributes to decarbonize hard-to-abate sectors on the short term, beyond a certain point, the availability of biomass and the remaining emissions associated with it combine to limit its role in approaching net-zero emissions outside of negative emissions applications.

3.6 References

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4

The evolution of GHG emissions in net-zero scenarios

The challenge of reaching net-zero emissions requires not only reducing emissions to their lowest possible levels, but also compensating for remaining emissions that are too difficult to eliminate. The latter are due to specific applications that involve extremely costly decarbonization or for which zero-carbon technology is not yet available, but that answer demands that are not projected to be eliminated. The discussion in this chapter thus focuses on the implications of the transformations needed within Canada's economic system to reach net zero.

Highlights

- Federal and, to a much smaller degree, provincial policies recently put in place or being finalized have combined with market developments to begin to turn the trend in GHG emissions downward. More specifically, the Clean Electricity Regulations and the Zero-Emissions Vehicle mandate lead to significant and structural emission reductions over the next 15 years or so.
- However, these developments mainly impact a subset of sectors (chiefly electricity generation and personal transport) and remain insufficient to put the country on a pathway to net zero by 2050, leaving around 80% of today's emissions (550 MtCO2e) for the reference scenario. As they deploy over more than a decade, these measures are not rapid or broad enough to reach the 2030 GHG reduction target of -40 to -45% from the 2005 level.
- With a REF scenario that projects a 14% GHG reduction for 2030 with respect to 2005 and a NZ50 scenario that must enforce deep and rapid transformation to meet the 40% reduction target for 2030, it now looks impossible for Canada to achieve its 2030 goals, short of cutting oil and gas production by 60 to 70% , even if taking into account the possible impact of nature-based solutions or emission credits imports from California.
- Net-zero scenarios show a very significant quantity of remaining emissions from all sectors combined (between 172 and 196 MtCO2e annually) in 2050, underscoring gaps in low-carbon technological solutions and the essential role of carefully applied carbon capture and storage (CCS) technologies in key sectors, including direct air capture (DAC) and bioenergy with CCS (BECCS), to help bring net emissions to zero. Increasing syngas production and use, which results in negative emissions from the biochar by-product, also plays an important role in this compensation.
- With current technologies, non-energy emissions (from agriculture, industrial processes and waste) occupy a much larger share of emissions around the net-zero point as they are difficult to reduce, short of technological disruptions or dramatic reductions in demand for the services they provide.
- In all net-zero scenarios, the transformation of the energy system requires considerable expansion of the infrastructures to produce, store, transport and distribute the energy mix, on a time scale that squeezes out any buffer, while at the same time investing in developing low-carbon options applicable to a broader set of sectors.
- Although cost-effective options are already decarbonizing buildings at a rate compatible with net zero by 2050, transformations will be limited by implementation challenges such as labour availability, supply chains, investments in the electricity sector, and regulations.
- While negative emissions play a key role in net-zero pathways, the specific technological solutions to achieve them are currently scarcely used, underscoring uncertainties surrounding this potential: planning strategies to assess their realistic potential should be developed in the near term.
- Since the role of citizens' daily actions in reaching net-zero targets is very limited and affects only a few sectors, it is important for governments to focus their actions first and foremost on industry and the energy and private sector in general.

4.1 What does net zero look like?

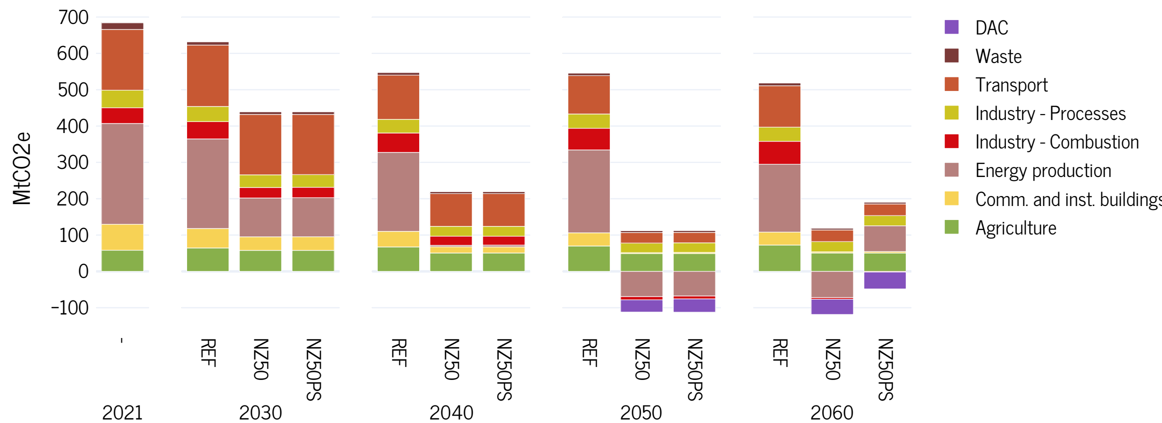
The policies and regulations, primarily federal, introduced in recent years result in significant GHG reductions, initiating low-carbon transformations that continue well into the 2030s.

The expected short- to medium-term transformation of some services has an impact on total emissions in REF (Figure 4.1). Emissions are 8% lower in 2030 than in 2021 (which represents a 14% decrease over 2005 levels)[1], and further transformations expected from the Zero-Emission Vehicle (ZEV) mandate and the Clean Electricity Regulations (CER) lead to a 20% reduction in emissions from today's levels by 2040.

Emission cuts in REF are nowhere near the net-zero trajectory and NZ50 levels depart from the trajectory seen in REF early on.

The distinction between the reference scenario and NZ50 is also quite clear across the entire time period. To enforce net-zero goals by 2050, the pace of emission reduction observed in NZ50 is much faster and deeper than in REF. By 2040, emissions are down 68% in NZ50, continuing to net zero by 2050, while REF reaches at best a 20% reduction in 2040 before plateauing as clean technologies barely compensate for demographic and economic pressure

Figure 4.1 – Total GHG Emissions by Sector



[1] When adding the potential GHG reduction impact from nature-based solutions and carbon credit imports from California, as used in Environment and Climate Change Canada projections, this reduction could reach 20%.

Hindsight in energy outlooks: the evolution of GHG emissions

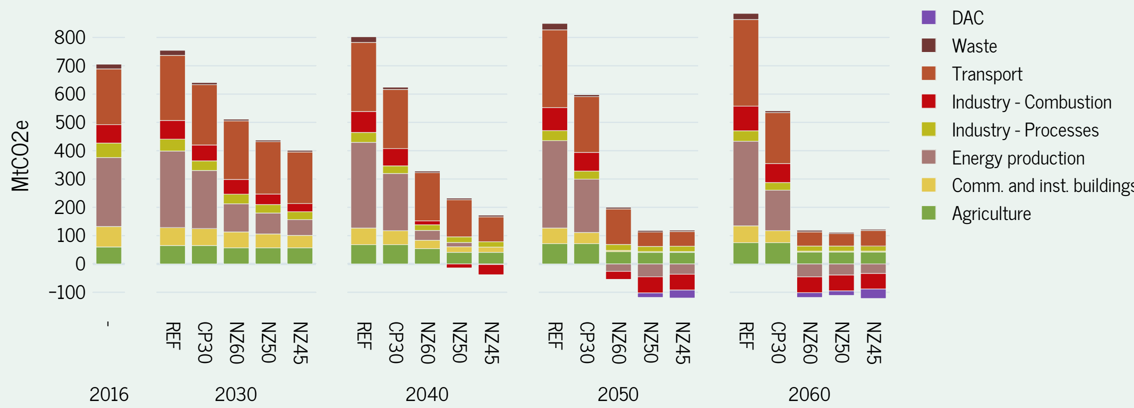
In the 2021 edition of the Canadian Energy Outlook (Langlois-Bertrand *et al.* 2021), we considered three core net-zero scenarios which varied in terms of the target date for reaching net zero (2045, 2050 and 2060, labelled NZ45, NZ50 and NZ60, respectively). One of the key results was that the main characteristics of the emissions structure around the net-zero point did not change much across these scenarios: in other words, changing the length of the time period to reach net zero mainly affected the pace in the reductions, bringing out the stability of the projections given the information available at the time.

Comparing these results with the current edition, it is clear that many such characteristics still stand. For instance, net-zero pathways would still be associated with a significant amount of remaining emissions, emanating mainly from industrial and agriculture processes, as well as some subsectors in transport. Therefore, the needs for emissions capture and storage are of a similar magnitude (between 172 and 196 $MtCO_2e$, when including biochar) and negative emissions technologies must be used to compensate for this.

Most negative emissions technologies the model opted for to neutralize remaining emissions are the same as in 2021: BECCS hydrogen production, and to a lesser extent for electricity and industrial heat production, remain the main group of technologies. DAC is also used in similar quantities (~30 $MtCO_2e$) as it was in 2021. Biochar, which was not included in the model in 2021 but now presents between 40 and 50 $MtCO_2e$ of storage, is one important addition to this toolbox of negative emissions.

While similarities between net-zero pathways may be significant, a major difference between the two modelling exercises is the expected evolution of emissions under business-as-usual conditions. In 2021, the REF scenario showed a continuous increase in emissions over time that ended at well over 800 $MtCO_2e$ in 2060. This is very different from this edition's 520 $MtCO_2e$ for the same year, which underscores the key role played by recent policy and regulatory changes, especially the Clean Electricity Regulations and the Zero-Emissions Vehicle mandate, which are both included in this

Figure 4.2 – GHG emissions by sector for the CEO2021



edition's reference scenario. The 2021 REF scenario also did not include the carbon pricing increase schedule to 2030 and we used an alternative reference scenario at the time (CP30) to assess this change. However, a comparison with this scenario is not direct, as CP30 also used more optimistic assumptions respecting new technology adoption, which are not used in the current modelling in order to comply with current observations about Canada's economy.

Even in net-zero scenarios, a significant quantity of emissions remains and must be compensated.

With current and projected technologies, despite the significant transformations to the Canadian energy system reviewed in Chapters 2 and 3, a large volume of emissions remains across all scenarios when net zero is reached (between 121 and 146 $MtCO_2e$, in addition to 44-50 $MtCO_2e$ of emissions already captured by CCS in industry). These emissions must be captured and sequestered — or compensated by the extraction of emissions from the atmosphere elsewhere.

The next sections examine these and other key differences and common points identified across scenarios, time and sectors in more detail.

4.1.1 Emissions reduction pathways over time

The reference scenario sees important transformations in the delivery of some services with different technologies and energy sources compared with today, which result from initiatives introduced in recent years.

The combination of the technological developments and policy implementation incorporated in REF shows a downward trajectory in emissions over time. As a result of these policies, most cuts come either from energy production (as electricity-related emissions are largely reduced by 2035 and methane emissions from oil and gas production also decrease, from the electrification of personal transport in the 2030s and from buildings. Given that reference scenarios modelled in previous editions of this Outlook did not show emissions reductions, this is a positive development.

However, cuts after 2040 are very limited in REF, even if total emissions do not rise again, as a result of current regulations and investments level up. Nevertheless, it is important to highlight that this high-level glance does not make it possible to reach any conclusions as to the effectiveness individual policies. Many factors other than current programs drive this downward emissions trend, including falling costs for low-carbon technologies. While it is beyond the scope of this report to assess the effectiveness of individual policies, the more detailed review of the evolution of emissions by sector presented below helps understand the breakdown of this trend in REF. However, our modelling exercise does not include additional pressure to decarbonize from individual choices and pressure from investors, the private market and external constraints imposed by Canada's trading partners.

The gap in emissions trajectories between NZ50 and REF is very wide, especially after 2030, providing a sense of the additional planning and transformations required to reach net zero by 2050.

If the downward trend in emissions is unmistakeable in REF, the size of the reductions remains far from Canada's emissions reduction targets (Figure 4.1). By design, NZ50 reaches both the 40% floor of the 2030 target and net-zero emissions by 2050, a level maintained in 2060. For this scenario, the middle point in between the two official targets (2040) shows a 70% reduction in comparison to today's levels. This reduction represents a 3% drop in emissions per year between 2030 and 2050 if an even faster decrease (of about 5%) is maintained between now and 2030, a yearly rate equal to 60 percent of the emission reductions observed in during the first year of the COVID-19 pandemic. Negative emission technologies, mainly in the form of BECCS processes, direct air capture and biochar production, appear in the 2040s and capture and store 128 $MtCO_2e$ yearly by 2050 (see Section 8.3 below).

Net-zero scenarios see transformations similar to REF in electricity production, buildings and personal transport on the shorter term but other sectors depart rapidly from REF's trajectory.

To reach 2030 federal targets (-40%), the NZ50 trajectory requires some sectors to cuts emissions dramatically on the short term. Buildings, for instance, see 50% of their emissions cut from 72 to 37 $MtCO_2e$ between 2021 and 2030 in NZ50, much more rapidly than in REF. Emissions reductions from transport are only slightly more important in NZ50 than REF before 2035 as they chiefly result from a decarbonization of passenger vehicles in both scenarios. However, after that NZ50 departs from REF to reach an 83% reduction by 2050.

Industry and agriculture also transform deeply on the short term in NZ50, resulting in important emissions cuts as well. Even more substantial is the change over time in emissions from energy production, which includes oil and gas production, electricity generation and hydrogen production. Even in REF, energy production emissions fall 11% by 2030 (from 277 to 247 $MtCO_2e$) with the help of the regulation on fugitive emissions. However in NZ50, the drop by 2030 is much more abrupt, with -61%, to 107 $MtCO_2e$, and the sector becomes a source of negative emissions by 2050.

A more detailed discussion of emissions by sector is provided below.

4.1.2 Remaining emissions in net-zero scenarios

A closer look at 2050 enables us to pinpoint the hard-to-abate sectors even in an optimized net-zero pathway. This is crucial in order to understand three things: (1) the sectors where emissions reductions are costlier with projected technologies than compensating them with direct air capture or other negative emission technologies; (2) the sectors where emissions reductions are unlikely without a significant reduction in demand for these activities or an unforeseen technological innovation; and (3) the implications of (1) and (2) in terms of neutralizing these remaining emissions, both in terms of the cost for deploying negative emission technologies from a virtual nil level today and in the technical challenges inherent in storing massive quantities of CO_2 over the longer term to keep this neutralization effective.

Reducing emissions beyond a certain point may be more costly than compensating them.

With regard to the first category outlined above, that is, compensations that are cheaper than reductions, the transport sector stands out, with 29 $MtCO_2e$ remaining in 2050. Importantly, this is assuming that passenger transport and medium-size road transport of merchandises and rail are fully decarbonized. Forty-three percent of the remaining emissions for transport in 2050 emanate from air transport (8 $MtCO_2e$), marine (3.3 $MtCO_2e$) and heavy road transport (1.1 $MtCO_2e$).

Close to 55% of the total comes from off-road transport (16 $MtCO_2e$), where a very eclectic mix of services and technologies make it difficult to design single policies. So far, little attention has been paid to these applications in emissions reduction policies, limiting the capacity of actors to determine a clear direction for decarbonization strategies.

Industrial and agricultural process emissions require disruptive technological innovation or production cuts, otherwise important emissions from these sources will remain.

Similarly to transport, industrial processes also play a major role in remaining emissions, with 26 $MtCO_2e$ left in 2050 in the net-zero scenario, although this is less than REF (39 $MtCO_2e$ in 2050). Agriculture emissions (outside of energy use) also retain 70 $MtCO_2e$ in 2050 due to the difficulty of significantly reducing emissions from soils, enteric fermentation and manure management past a certain level.

Both industrial and agricultural process emissions correspond to the second category described above: these emissions are difficult to reduce further without significantly cutting back on production or the advent of a key innovation in technology or practices. In any case, these areas require special attention as soon as possible in order to identify possible strategies and build roadmaps tailored to specific applications.

A significant quantity of negative emissions are necessary to complete the balancing of these remaining emissions, including some direct air capture (DAC).

As mentioned previously, in the absence of breakthroughs, negative emissions are substantial in net-zero scenarios. In 2050, they come from biochar (-51 $MtCO_2e$) and BECCS applications (-43 $MtCO_2e$) in hydrogen production, electricity generation and industry. Direct air capture contributes as well, with 34 $MtCO_2e$ captured and stored in 2050.

It is important to note that these negative emissions are realized in addition to other CCS applications in industry (44 $MtCO_2e$ in 2050), bringing the total emissions to be stored yearly to 172 $MtCO_2e$, including 51 $MtCO_2e$ stored in biochar and the rest in geological storage. This would require a massive and rapid expansion for this sector as the number of existing installations able to capture and store CO_2 underground is extremely limited. This limitation highlights the magnitude of the technological and infrastructure challenge suggested by these results unless more significant emissions reductions are realized than in NZ50, reducing the need for negative emissions and carbon capture.

4.2 Emissions by sector

Sectoral emissions can be compared along different aspects, such as the degree of decarbonization over time (and once the country reaches net zero), the pace at which reductions are realized in NZ50, and the more precise sources of emissions within the sector that may evolve differently to deliver the aggregate reduction.

4.2.1 Residential and commercial buildings

Due to the energy mix used in buildings, space heating is by far the main source of emissions for both commercial and residential buildings.

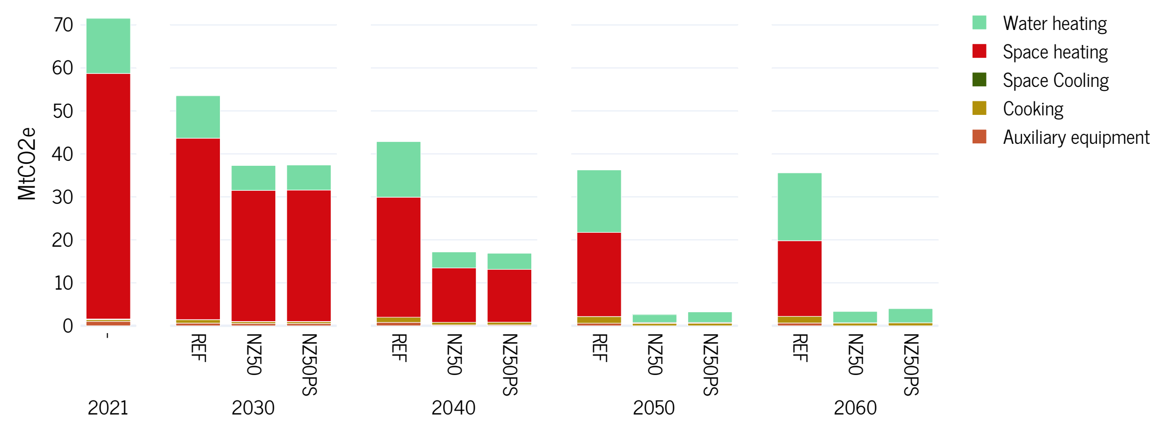
Energy services in buildings include space heating and cooling, water heating, appliances and auxiliary equipment, as well as lighting. Since many of these services are already powered by electricity across the country, the sources of direct GHG emissions in buildings, that is, not counting emissions associated with the building materials, are few. Space heating is by far the largest source, producing 87% of emissions in commercial and institutional buildings and 73% in residential buildings. As a result, pathways for the buildings sector chiefly vary in terms of the extent of the decarbonization of space heating and to a lesser extent water heating.

In REF, transformations are already reshaping the emissions footprint of buildings, while emissions from space heating are completely eliminated in NZ50.

Due to the availability and relatively low cost of air-source heat pumps, as well as some publicly funded incentives to opt for these technologies when renovating, the transformation to space heating across the building fleet is already underway. In REF, buildings see a substantial reduction in these emissions: in residences, the decrease is 34% by 2030 and 71% by 2050, after which reductions are modest. The reductions are slower in commercial buildings, with 18% less by 2030 and 61% by 2050.

In NZ50, the 2030 GHG reduction target results in a more rapid decarbonization of buildings as one of the cheapest ways to reduce across sectors. By 2030, 58% of space heating emissions are eliminated in residential buildings and 36% in commercial buildings on the way to a complete decarbonization of the service by 2050. Of course, this transformation also requires an increase in electricity production and a reinforcement of the grid, as discussed below.

Figure 4.3 – Buildings sector emissions



Water heating emissions grow in REF to become the most important source by 2060 and are more difficult to eliminate even in net-zero scenarios.

If space heating is transformed at low cost across all scenarios, water heating is expected to continue increasing its emissions. This rise is largely the result of less attention being paid to water heating technologies in current government programs targeting buildings, which mainly focus on heat-pump installations, heating oil conversions and thermal retrofits. As a result, water heating emissions remain at current levels throughout 2060 in commercial buildings and grow by 25% in residential buildings by 2060.

In NZ50, water heating is substantially decarbonized. On the 2030 horizon, 55% of emissions linked to water heating are eliminated and by 2050 this reduction climbs to 86%. In fact, emissions from water heating in residences remain the largest emissions source for buildings in 2050 and 2060. In reality, it is unlikely that residential clients will retain gas only for water heating, leading to lower emissions for this sector than projected by both REF and NZ50 by 2050, as long as building heating follows the projected decarbonization curves.

Implementation challenges make NZ50 results unlikely to be achieved on the short term, despite a substantial contribution from energy efficiency initiatives.

Although the fast-paced reductions in space heating emissions reflect the technology maturity and its relatively low cost on the very short term, a reduction of this size remains unlikely because of implementation issues. There are considerable logistical challenges to decarbonizing this number of existing buildings over just a few years, especially given that the modelling includes a large number of deep retrofits of existing buildings in addition to switching space heating systems. New constructions, which will increase rapidly due to population growth, require urgent attention to ensure that they are significantly more energy efficient and are already equipped with zero-emission technologies.

Moreover, electrifying space heating to this extent and at this pace requires careful planning of the impacts on peak electricity demand and the pressure it creates on grids. In any case, the results for emissions trajectories in buildings for net-zero scenarios suggest that these reductions from technology switching in space heating are a low-hanging fruit and that efforts should aim to capitalize on this opportunity.

4.2.2 Transport

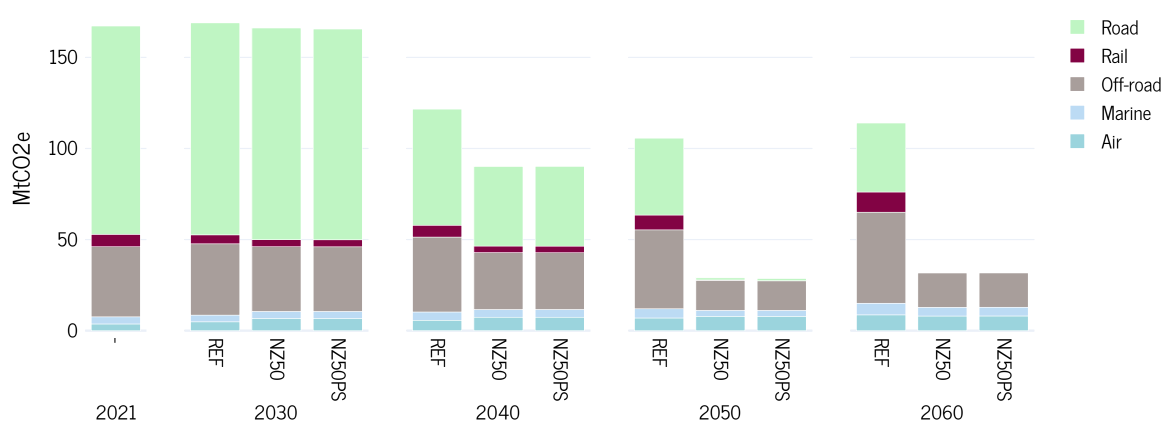
The transport sector, one of the main sources of emissions today, remains so in 2050. Even in the net-zero scenarios, this sector still emits between 29 and 32 $MtCO_2e$ in 2050 and 2060 respectively, illustrating the technological challenges of fully decarbonizing the sector.

Short-term emission trajectories are similar in REF and NZ50, a result of recently introduced measures for passenger transport and the higher cost of decarbonizing other subsectors.

In the REF and NZ50 scenarios, emissions stagnate until 2030, before declining 7% (REF) and 10% (NZ50) by 2035. The bulk of this reduction comes from passenger road transport, where emissions decrease 16 $MtCO_2e$ by 2035, from 58 $MtCO_2e$ in 2021. This decline is a direct result of the zero-emission vehicle mandate, which is included in all scenarios.

The importance of the electrification of light-duty passenger vehicles on REF is undeniable: aside from passenger road transport, no other transport sub-sector sees significant reductions, with only a small reduction in rail (2 $MtCO_2e$) resulting from short-term electrification. In contrast, 10% (3 $MtCO_2e$) for the off-road sector and 43% for rail (3 $MtCO_2e$) are cut by 2030 in NZ50, resulting from a more aggressive electrification of these sub-sectors in the net-zero pathway.

Figure 4.4 – Emissions from the transport sector.



After 2035, decarbonization accelerates in NZ50, while further reductions in REF are limited to the renewal of the passenger car fleet and the partial decarbonization of freight trucks.

In REF, emissions in the road transport subsector continue to fall given the lingering effect of the ZEV mandate for passenger vehicles. By 2050, a substantial 37% of today's transport emissions are eliminated, bringing them down to 105 $MtCO_2e$, and include a partial decarbonization of medium and heavy-duty trucks (hydrogen and natural gas come to replace 82% of oil products as the main fuel for heavy-duty trucks). However, this remains far from the figure in NZ50, which imposes a much more rapid transformation of the sector after 2035, ending with a 83% reduction to 29 $MtCO_2e$ in 2050. Road transport is almost fully decarbonized by 2050 (with 1 $MtCO_2e$ remaining).

The difference between REF and NZ50 is greater for rail, which is fully decarbonized in NZ50, while emissions are 20% higher than today in REF in 2050 and 65% higher in 2060. Similarly, off-road emissions are down 57% (to 17 $MtCO_2e$) in NZ50 for 2050, compared with a 13% increase in REF (to 43 $MtCO_2e$).

For the transportation sector overall, we observe a very significant gap between NZ50 and REF after 2035: in 2040, emissions are already 26% lower in NZ50 than in REF, and by 2050 the gap reaches 73%, with 105 $MtCO_2e$ remaining in REF. The pressures on demand from population growth after 2050 also have a more limited impact in NZ50 (where emissions grow to 32 $MtCO_2e$) than in REF (114 $MtCO_2e$). As for other sectors, measures currently in place are far from sufficient to impose the transformations needed to put the sector on a pathway to net-zero by 2050.

The decarbonization of air and marine transport remains very costly, as emissions continue to grow even in NZ50.

In the absence of mature and cost-effective technologies to decarbonize energy use in air transport, emissions increase over time in all scenarios. In REF, emissions grow 89% over today's levels by 2050. In NZ50, the growth is even more substantial, climbing to 113%. While significant growth observed in all scenarios is partly due to the reference year (2021), where flight restrictions were still significant, the difference in emissions between REF and NZ50 is more fundamental. As REF projects the airline industry to use of a significant fraction of biomass feedstock to produce and use biojet, the net-zero constraint of NZ50 means that biomass resources are prioritized for negative emissions and other types of bioenergy where emissions reductions are more important, leaving no low-carbon solution for fueling air traffic.

Given the current options available and their cost, decarbonizing marine transport is also very difficult. NZ50 is nevertheless able to cut 16% of emissions by 2050, compared with an increase of 30% in REF. These emissions remain a small share of the total for the sector in REF but, given reductions elsewhere in NZ50, they amount to 10% of remaining emissions in 2050.

The relative importance of off-road transport emissions grows over time as off-road transport becomes the largest source of emissions in NZ50 by 2050.

Despite attracting very limited attention in decarbonization efforts so far, off-road transport represents 23% of emissions for the transport sector today, a category that includes all motorized transport onsite in industrial and commercial facilities, as well as in agriculture.

In REF, emissions from off-road transport grow slowly but continuously for the entire period, reaching 43 $MtCO_2e$ in 2050, a 13% increase over today's levels. In NZ50, the significant decarbonization of some of the services within this subsector, mainly with electricity or hydrogen, leads to reductions of 10% in 2030, 36% by 2050 and 57% by 2060. With 16 $MtCO_2e$ remaining in 2050, this certainly represents an important departure from REF.

Even more importantly, these results show that in both REF and NZ50, off-road transport becomes the most important source of transport emissions by 2060, at 41% and 57% of the total for each scenario respectively, which suggests that much more attention should be paid to developing roadmaps to decarbonize the eclectic list of services supplied under this category.

Both the similarities and differences between NZ50 and REF highlight out important lessons in the outlook for the transport sector.

Key similarities across NZ50 and REF suggest that emissions in this sector will be slowly trending down in the coming years, before a significant drop in road passenger transport in line with the ZEV mandate and some electrification of rail is noted, while the share of emissions from off-road increases over time. Decarbonization strategies for these sources of emissions can thus focus on acceleration since the expected reductions are already on a pathway compatible with NZ50 – just not at the required pace.

Nevertheless, even this short-term partial resemblance must not obscure the fact that measures supporting these transformations in REF have limits well below what is needed to decarbonize. NZ50 forces changes that are too costly to happen on their own and could require significant new infrastructure for key subsectors like catenary lines, charging stations or hydrogen networks for heavy transport. This situation illustrates the inability of current incentives to deliver beyond a certain point and in the absence of measures directly targeting other transportation subsectors, reductions for the sector are chiefly limited to small road vehicles.

We also note that while individual transport can be decarbonized with the help of a dominant technology (battery-electric), multiple technologies are still possible to decarbonize heavy transport. As each would require significant public infrastructures, identifying a winning approach and setting up regulatory orientations, similar to ZEV mandates, will need to be rapidly achieved if this sector is to be decarbonized by 2050.

4.2.3 Agriculture

Although agriculture represents only 8.5% of current GHG emissions, it is projected to become the largest source of remaining emissions in net-zero scenarios, with around 49 $MtCO_2e$ or 44% of remaining net emissions in both 2050 and 2060. Agriculture emissions come both from energy combustion, for instance for heating and light, and from process emissions, such as from enteric fermentation or soils. Agricultural vehicle emissions are not included here and as they come under the off-road transport sector. If heat production can be decarbonized, few low-carbon solutions are currently available for process emissions, which represent by far the largest share of emissions from agriculture (95% today excluding emissions categorized under off-road transport).

> **Energy-related emissions from agriculture are completely eliminated in NZ50, in sharp contrast to REF.**

While energy-related emissions from all categories continue to grow in REF, net-zero scenarios reduce them quickly. By 2040, 77% of these emissions are eradicated and the rest are eliminated before 2050, primarily through electrification with a contribution of syngas to the mix.

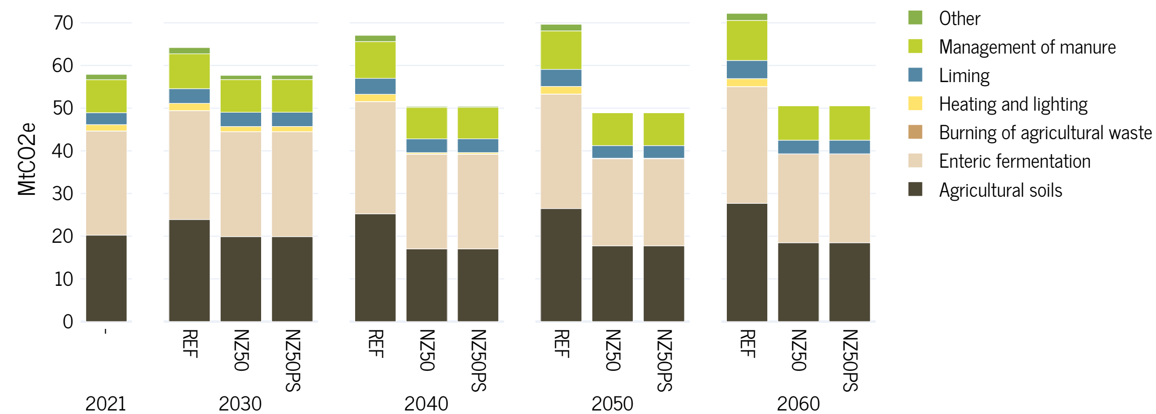
The picture is similar for other energy-related emissions in agriculture that are categorized under off-road transport. REF sees these emissions grow 30% by 2050, while NZ50 reduces them by 85% over the same period. Using electricity and hydrogen. By 2060, off-road transport in agriculture is fully decarbonized in NZ50, largely through the use of electric technologies and a small share of biofuels, while 14 $MtCO_2e$ remain in REF.

> **Process emissions are much more difficult to avoid, even though NZ50 brings them under control while they continue to grow in REF.**

Process emissions represent the overwhelming share of agriculture emissions, even when including off-road transport emission associated with the sector. In REF, these emissions grow by 11% by 2030 and 20% by 2050, reaching 66$MtCO_2e$.

In NZ50, relatively modest emissions cuts are realized, growing a gap with REF over time. Emissions do not increase to 2030, remaining at 55 $MtCO_2e$ in contrast to REF. By 2050, reductions lead to 12% fewer emissions (49 $MtCO_2e$) than today, which represents 26% fewer than in REF for that year. Trends for both scenarios continue to 2060, although NZ50 is unable to reduce emissions further and shows a slight rebound due to increased demand in the sector.

Figure 4.5 – Emissions from agriculture (process and energy-related)



Here again, remaining emissions in the NZ50 scenario underscore the current absence of credible low-carbon approaches and highlight the need for more research and development in this field.

> **Limited options are available to decarbonize process emissions in agriculture, directly adding difficulty to net-zero pathways.**

Short of cutting demand for agricultural products, there are limited options known today able to drive large reductions in process emissions. In NZ50, the changes are associated with better management of soil nutrients and cuts in enteric fermentation from optimized feed mix and other techniques.

We also note that cutting demand is not necessarily linked to food consumption as the sector also produces a significant quantity of crops for biofuels. Attention should therefore be paid to this share of agricultural production since the use of biofuels from fuel crops contributes in part to the emissions from soils.

4.2.4 Industry – processes and combustion

As for agriculture, emissions from non-energy producing industry can be divided into those from energy combustion, for instance in heat boilers, and those resulting from the processes used to transform materials, such as the reduction of iron ore in steelmaking. Contrary to agriculture however total emissions for the sector are almost evenly split today, with 43 $MtCO_2e$ in energy-related emissions and 48 $MtCO_2e$ in process emissions. Energy production industries, which are not addressed in this section, are discussed in section 4.2.5.

Total industry emissions slightly rise in REF (7.9% increase by 2050, from 92 to 99 $MtCO_2e$) and the combustion category becomes net negative by 2050 in NZ50, while industrial process emissions are reduced to 54% of today's levels despite the sector's growth. These figures also illustrate the difficulty of eliminating emissions from industrial processes while meeting demand projections as each individual process requires a low-carbon innovation to replace it.

Combustion emissions are projected to increase substantially in the reference scenario.

Following the projected rise in demand, industry as a whole increases combustion emissions by 10% before 2030 and 38% by 2050 in REF, jumping from 43 to 60 $MtCO_2e$ between 2021 and 2050. As discussed in Chapter 2, in REF we project relatively small changes in the energy mix for the sector – where electrification has limited impact and other fuels increase only marginally – as well as the fact that the modelling used here assumes a constant industrial structure. These results may therefore understate the importance of new industrial activities in the evolution of emissions over time. We note also that CCS penetrates the sector only marginally in this scenario.

Figure 4.6 – Emissions from industry (energy combustion)

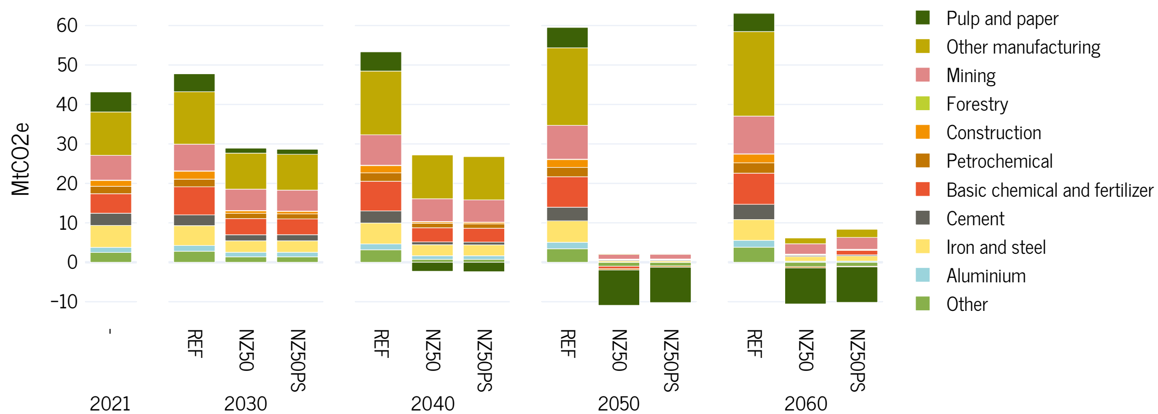
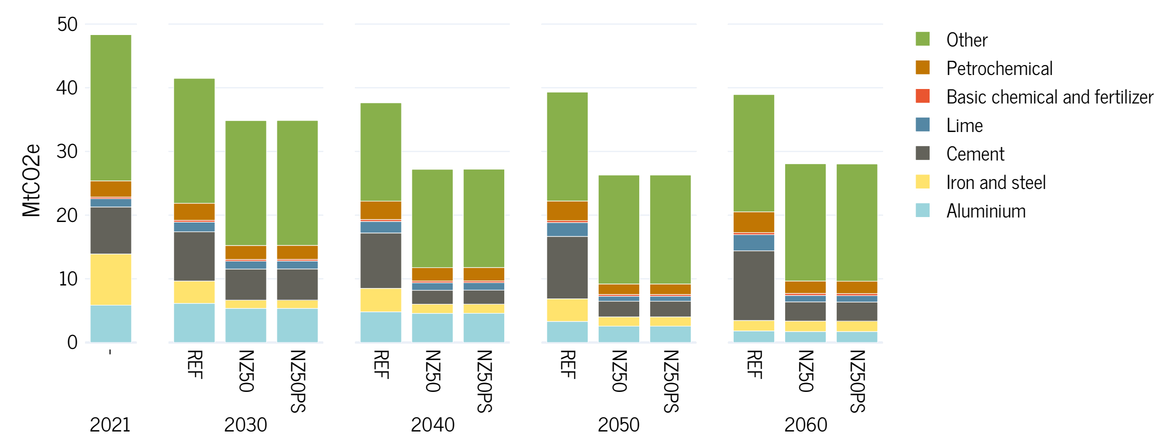


Figure 4.7 – Emissions from industry (processes)



In NZ50, the sector's combustion emissions include net negative emissions starting in 2040, while industry becomes net negative as a whole from 2050.

The net-zero constraint leads to a drastic departure from REF in terms of combustion emissions. Already by 2030, NZ50 emissions are down 33% from current levels, to 29 $MtCO_2e$ and 43% (25 $MtCO_2e$) by 2040. These decreases are the result of a wide range of transformations, including CCS applications in cement, the decarbonization of heat in iron and steel as well as basic chemical and fertilizer manufacturing, and emissions reduction in other manufacturing activities. The pulp and paper sector also slashes its emissions by 72% in 2030, contributing the previously mentioned 33% decrease.

Although these transformations take place at a slower pace from 2030 to 2040, net negative emissions for some subsectors emerge in 2040, notably in pulp and paper where BECCS processes increase in importance. Most of the transformations are continued throughout the 2040s to reach a total of -9 $MtCO_2e$ for the sector as a whole, resulting from pulp and paper and lime manufacturing contributing negative emissions, as well as all subsectors eliminating over 90% of their combustion emissions.

Process emissions evolve differently than energy-related emissions, even in REF, as some economically competitive decarbonization innovations are projected to penetrate the sector.

Owing in large part to a transformation of the steel industry, where blast furnaces with coke reduction are being replaced, as well as reductions in the production of halocarbons, process emissions are projected to decrease 14% in REF before 2030, from 48 to 41 $MtCO_2e$. Further emissions associated with halocarbon manufacturing processes lead the additional reductions by 2040, reaching a low point of 38 $MtCO_2e$ for process emissions in the scenario. Emissions are then relatively constant falling to levels 19% lower than today in 2050.

Although reductions are more substantial in NZ50, they are nowhere near full decarbonization. In 2030, levels are down 28% from today to 35 $MtCO_2e$ and by 2050 this reduction reaches 46%. While these reductions are significant, levels in 2050 are 26 $MtCO_2e$, compared with REF's 39 $MtCO_2e$, which highlights the difficulty of avoiding process emissions short of currently identified technological alternatives – or a decrease in production.

To illustrate this point further, NZ50's reductions are accomplished in the same limited list of subsectors as in REF. Iron and steel emissions are reduced more aggressively and halocarbons production follows a pathway similar to REF. Additional reductions come from aluminum production and petrochemicals. The only important difference between the two scenarios is noted in cement production, where REF does not achieve reductions, contrary to NZ50 with 67% cuts by 2050, a result from a blanket application of CCS technologies. No other industrial sector sees process emissions reductions.

Decarbonizing industry goes through additional measures to induce transformations in the energy mix and innovations in processes.

From this portrait, it is clear that decarbonizing industry requires tailored approaches to specific sectors and their processes. Roadmaps for key sectors should be developed as soon as possible to explore options for economically viable low-carbon process emissions in particular. If they are not, decarbonizing industrial processes in Canada will remain largely dependent on efforts and regulations in other parts of the world.

4.2.5 Energy production, including electricity

Even more substantial is the change over time in emissions from energy production, which includes oil and gas production, electricity generation and hydrogen production. Even in REF, energy production emissions decline 11% by 2030, from 277 to 247 MtCO2e, and another 10% by 2040 to 217 MtCO2e, owing to the closure or retrofitting of coal-fired powerplants, better control of fugitive emissions, and some reduction in natural gas-fired generation expected in response to the Clean Electricity Regulations. In NZ50, the reduction by 2030 is much more abrupt at -60%, falling to 107 MtCO2e, and the sector becomes a source of negative emissions by 2050, capturing 70 MtCO2e.

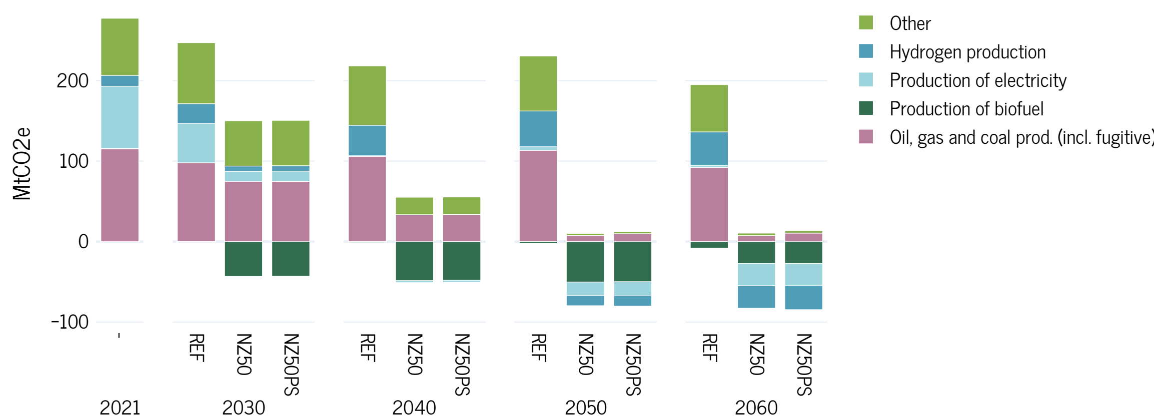
Chapter 3 presented the profound transformations required in the energy production sector to achieve the net-zero target. This section discusses these transformations from the perspective of GHG emissions.

> **With primary energy production of fossil fuels cut significantly in NZ50 and the very rapid decarbonization of electricity production, the emissions trajectory diverges rapidly from REF**

While REF reduces today's emissions (277 MtCO2e) by 11% (30 MtCO2e) by 2030, driven in part by regulations on fugitive emissions, the 40% GHG reduction target over the same period in NZ50 forces a substantial 170 MtCO2e cut from today's level. About half this reduction derives from oil and natural gas production cuts, coupled with a further associated reduction of methane emissions from the same production.

The other half of the emissions cuts for NZ50 is due to the much faster decarbonization of electricity production than in REF (84% reduction over today's levels, compared with a 37% reduction in REF). In addition to these cuts, NZ50 manages to add -44 MtCO2e in negative emissions through biochar production. The net total for 2030 in NZ50 is therefore 107 MtCO2e for energy production, which is 61% lower than today's levels.

Figure 4.8 – Emissions from energy production (including fugitive emissions)



> **While emissions in REF decrease a further 12% between 2030 and 2040, energy production emissions are almost net zero by 2040 in NZ50**

A decade later, emissions are down to 217 MtCO2e in REF, as electricity production is virtually decarbonized in response to the CER and mandatory methane emissions reductions are fully realized. Over the same horizon, NZ50 however is almost net zero (4 MtCO2e in 2040). Electricity production is slightly net negative because of some BECCS production (-2 MtCO2e), biochar emissions reach -49 MtCO2e, and oil and gas production decrease emissions 71% compared with today, due in large part to lower crude oil production levels. Heat production from natural gas is also much less significant, resulting in a further 45 MtCO2e decline compared with REF.

These trends carry on in 2040 as secondary energy production in NZ50 continues its decarbonization to lead the sector to significant negative emissions, playing a determinant role in enabling the achievement of the economy-wide net-zero pathway.

By 2050, total emissions for the energy production sector reach -70 $MtCO_2e$ in NZ50, compared with +228 $MtCO_2e$ in REF, a 298 $MtCO_2e$ spread. The role of the sector's multiple transformations in realizing the net-zero pathway therefore cannot be understated. These transformations take four main forms:

1. Electricity and hydrogen production expand dramatically but in ways that maximize the contribution of BECCS processes, resulting in negative emissions.
2. Biofuels production also becomes net negative, using the negative emissions from biochar produced alongside syngas.
3. Centralized heat production from natural gas is eliminated. Taken together, these three elements lead secondary energy production emissions to -77 $MtCO_2e$.
4. Lastly, oil and gas production emissions decrease by 90%, a result not only from much lower production levels (see Chapter 3), associated in part with a lowering of the demand for fossil energy, but also from rapidly tighter regulations for methane emissions.

These transformations highlight the key importance of the energy production sector in net-zero transformations, as well as its multiple facets that though they are well beyond the role of oil and gas production reductions are nonetheless essential.

4.3 Carbon capture and emissions neutralization

Achieving – and remaining at – net zero requires a significant quantity of emissions capture and storage.

As discussed in the previous sections and chapters, reducing all emissions to a minimum level implies deep transformations of all sectors toward a low-carbon delivery of services. Part of these transformations are accomplished through the use of emissions capture: in NZ50, total emissions captured in 2050 to ensure neutral emissions across the economy are already 11 $MtCO_2e$ in 2030, a quantity that grows substantially after 2040 to reach 121 $MtCO_2e$ in 2050 and 160 $MtCO_2e$ in 2060 (Figure 4.8). These transformations include CCS applications in industry and in energy production, as well as direct air capture.

More specifically, significant negative emissions are required in addition to other capture in industry.

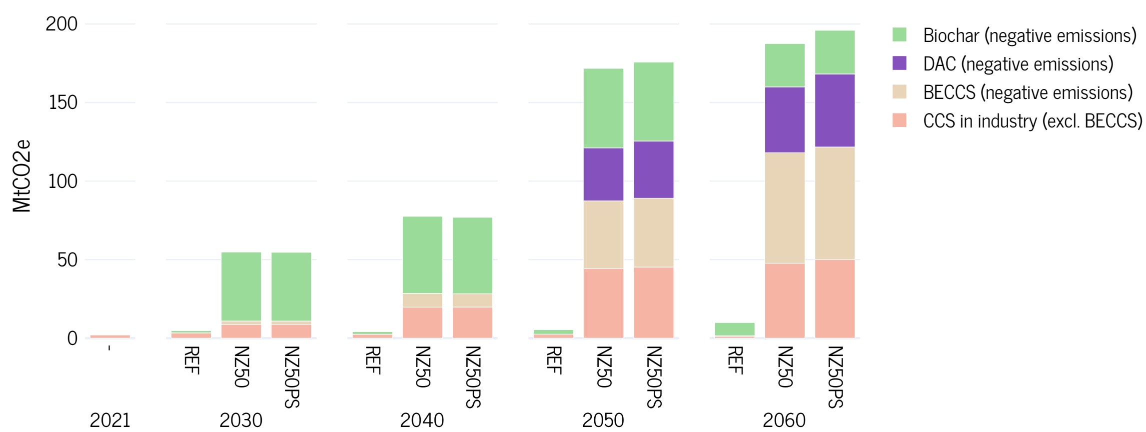
However, to achieve net zero whatever emissions remaining across the economy must be compensated by additional carbon removals from the atmosphere. CCS applications in industry or energy production, even when reaching capture rates above 90%, are emissions reductions rather than carbon removals. As a result, NZ50 requires more than CCS and negative emissions applications are used instead.

NZ50 requires 128 $MtCO_2e$ of negative emissions by 2050 in addition to CCS in industry.

As Figure 4.1 shows, to neutralize remaining emissions to reach net zero in NZ50 the sum of net emissions from sectors where these are negative must reach -112 $MtCO_2e$ by 2050. While this quantity is already massive given the starting point today, this figure can be misleading, as emissions are represented by sector. As a result, numbers are net emissions for each sector, which implies that the actual negative emissions required to reach these net levels are higher. A closer look is needed to understand this gap closer look.

Figure 4.9 describes these needs more clearly, showing emissions captured in industry, in BECCS operations, in direct air capture and in biochar. Energy production with BECCS is used to produce 43$MtCO_2e$ in negative emissions by 2050, which includes hydrogen production through biomass gasification and biomass-fired electricity generation. Direct air capture contributes another 34$MtCO_2e$. While not a capture process strictly speaking, the production of biochar as a co-product to syngas results in an additional 51 $MtCO_2e$, for a total of 128 $MtCO_2e$ negative emissions.

Figure 4.9 – Captured and negative emissions across scenarios



It is important to note that non-BECCS capture applications in industry, which reach 44MtCO_2e in 2050, must be added to account for all emissions stored. As a result, total storage implied by the NZ50 scenario to reach net zero is 172 MtCO_2e, including the 51 MtCO_2e in biochar used in soil amendments.

The levels of capture and storage indicated by these results would require the deployment of technologies that are quasi-inexistant at commercial scale today at an extremely rapid pace.

The lack in current capacity for each of these technologies or processes, with the exception of some CCS in fossil fuels-based energy production at efficiencies well below 90%, should highlight the magnitude of the expansion required to reach these levels within the 2050 timeframe in the scenarios presented here. Very few BECCS installations exist worldwide and DAC has yet to reach commercial scale.

While results indeed suggest a rapid ramp-up of capture capacity from DAC and BECCS hydrogen production only from 2040, it would be wise to determine their realistic potential well before then and carefully plan the deployment, while also working on direct decarbonization technologies that would limit the need for these negative emission solutions. This also holds true for emissions storage options: while theoretical potential is important, because of the very limited experience with such operations they should be assessed with caution.

Two important points should be made here. First, while the model uses numbers from the literature regarding costs and efficiency, no large CCS infrastructure currently operates with CO_2 capture rates near 90%, much less 95%. Accordingly, the cost of capturing and sequestering CO_2 may be largely underestimated.

Second, DAC, even if it works at costs used here, will require large quantities of clean electricity, competing directly with other sectors that need to electrify to decarbonize. The development of a DAC industry would therefore be a balancing act between achieving some negative emissions and slowing down the direct decarbonization of our economy.

CCS levels in net-zero scenarios also imply that it must be used only where no alternative is available.

Perhaps more importantly, it must be noted that these needs result from an optimized scenario and are certainly an understatement of the real needs for capture and storage to reduce and neutralize emissions on the way to net zero. Accordingly, CCS applications must be limited to where they are an absolute necessity, that is, where no alternative technological or reduced demand options exist.

Results for the REF scenario show that planning and incentives will be essential to deploy capture and storage technologies compatible with net-zero pathways.

CO_2 captured levels in REF are extremely limited and even decrease after 2030, illustrating the high cost of these applications under current conditions. No BECCS hydrogen or electricity production is expected to emerge, barring incentives or regulations making it possible. The same holds true for DAC. Even biochar production and use, which in some cases can provide negative emissions at a much lower cost, would require policy incentives given its very limited use today. The above underlines the need for a carefully designed deployment strategy to support the efforts toward net-zero emissions.

General observations:

- While current policies are expected to lead to important emissions reductions in buildings, personal transport and electricity production, major and rapid additional measures are required to put the country on a pathway to net zero by 2050.
- Reaching net zero by 2050 requires deep transformation of our energy production sector over the next 15 years, with considerable investments in electricity production and a significant drop in oil and gas emissions.
- Reaching and maintaining net zero beyond 2050 requires an annual capture of between 121 and 160 MtCO_2e, in addition to between 28 and 51MtCO_2e in negative emissions through biochar production.
- Non-energy emissions, in particular those linked to agriculture, become the majority of the remainder once carbon neutrality is reached, which poses a different challenge than reducing emissions from energy consumption since it necessitates disruptive technological innovation which is difficult to predict.
- Most emissions in Canada today are associated with industrial and commercial activities, including natural resources extraction, production of goods, commercial buildings and freight transport, contributing to 78% of Canada's emissions (85% when agriculture is also included), which are beyond the direct action of citizens.

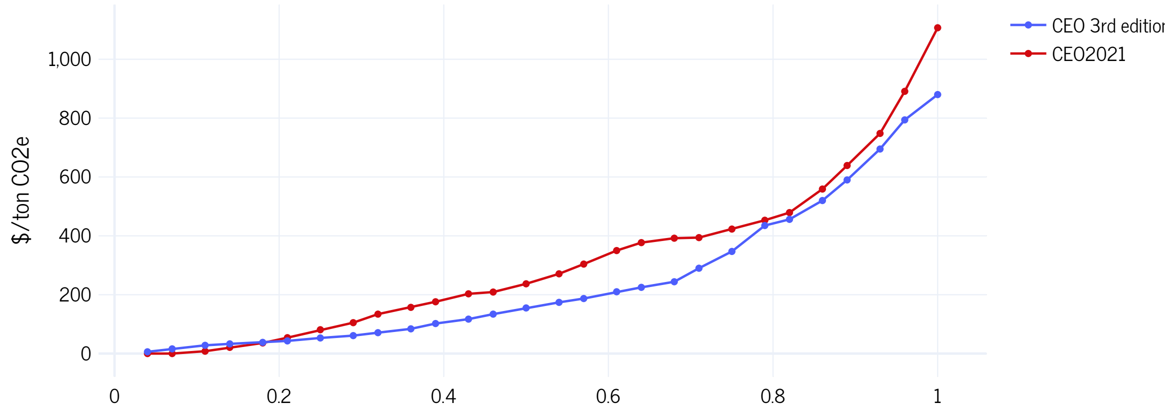
4.4 The cost of reducing emissions

The cost of reducing emissions increases with the depth of the cuts. Early reductions are typically low-hanging fruits; in other words emissions from sources resulting from economic inefficiencies are the result of path-dependent developments over time in various sectors. Once more attention is paid to these inefficiencies, the cost of reducing emissions by improving the processes is relatively low. This is why most GHG reductions have been obtained around the world in the past two decades simply by paying more attention to cases where more energy efficient alternatives were readily available – although in some instances locked out due to market failures – and where regulatory and policy measures were able to initiate transformations. The rapid expansion of wind power production and the phase-out of its coal-fired equivalent concur with this description.

However, as we progress further in net-zero pathways, reductions are increasingly harder to achieve, technologically, economically and socially. They require more significant changes in dominant practices and preferences, as well as low-carbon technologies that may be more expensive since they do not yet exist at scale, or new infrastructure to deploy before they are adopted. This is why in a cost-optimization modelling exercise like the one presented in this report, a net-zero scenario like NZ50 progressively drifts away from the reference scenario, as the cost of transformations forced into NZ50 to achieve the net-zero target is increasingly higher than the business-as-usual scenario, and regulatory or policy constraints and support mechanisms are lacking.

A look at the marginal costs of reducing emissions over time helps illustrate how the challenge of deep reductions becomes more difficult, and thus costly, over time. Figure 4.9 represents the marginal cost for reductions in NZ50 vs. REF, where reductions are indicated as a share of the total GHG reductions necessary to reach net zero by 2050. The curve shows how costs rise more quickly for the latter set of emission reductions, reflecting the complexities of deep reductions and the uncertainties respecting some technologies, including for carbon capture and negative emissions. In the current exercise, marginal costs once net zero is attained reach $880 for the last tonne of CO_2e eliminated at the net-zero point. Depending on the point of view, this cost may seem high or low, as discussed in more detail below.

Figure 4.10 – Marginal cost of GHG reductions, NZ50 scenario compared with REF



First, for NZ50, which imposes the current federal aspiration of 40% reduction by 2030 (compared with 2005 levels) and neutral emissions by 2050, the marginal cost remains under \$80/tCO_2e for achieving the 2030 target. In other words, most of the additional reductions in emissions required to fill the gap between the reference scenario and meeting the target could be achieved at a cost well below that level. The same logic applies to the 2050 target: while reductions of over 500 MtCO_2e are required to reach net zero compared with the reference scenario, around half could be achieved at less than 150\$/tonne.

Second, we can compare these results with those obtained in the Canadian Energy Outlook 2021 (Langlois-Bertrand *et al.* 2021). The reference scenario back then also included all policies in place at the time, as does the current one. The marginal cost for the last tonne reduced in the current NZ50 is 880\$/tonne, while the cost of the same last tonne to reach net zero in 2021 was \$1,100. Technological developments since the previous Outlook, which help not only with providing emission reduction solutions, but also with reducing uncertainties about technological paths and their costs, have in less than three years resulted in a very significant marginal cost reduction. This is also visible in the gap between the two curves before reductions reach 80% of what is needed for net zero, where marginal costs for this editions' NZ50 scenario are well under those of 2021, despite the fact that the current REF scenario already reduces emissions well beyond its 2021 equivalent.

As we pointed out in a similar discussion in the 2021 edition, this shows how marginal costs are a rapidly moving target: as significant action is taken to reduce emissions, innovation leads to a decrease in the cost of further reductions. This is achieved as new technologies, solutions, approaches and applications are put in place. As a result, projected marginal costs are reduced as the transition occurs. More importantly, as countries move on the transition, the higher levels estimated for the last tonne reduced become less relevant since it affects a smaller proportion of reductions.

Yet it should also be emphasized that the marginal price for the last tonne is controlled by our estimation of carbon capture and sequestration (CCS) technologies, both on industrial sites and in direct air capture (DAC) installations. These technologies present a number of physical and technical challenges that have yet to be overcome before moving to scale. This uncertainty contrasts with the low-carbon technologies that cost less but are also already deployed, providing much greater confidence as to their role in the energy transition.

4.5 Takeaways

The progress achieved in curbing the trend in emissions downward, illustrated by the REF scenario, is encouraging. A closer look at these results, and at the contrasts with NZ50, shows however that many of the drivers of this change compared with past expectations result from concrete actions taken within Canada. In other words, a large part of the reductions in GHG emissions in the reference scenario are expected to be the direct result of strong policy and regulatory action. The corollary is that **bridging the important gap that remains with a net-zero pathway will require several other strong measures, as well as a successful implementation of those already announced, to support and orient the major investments in infrastructure that are required over the next 10 to 15 years**.

As part of these additional measures, more attention should be paid not only to sectors like heavy merchandise transport that are unlikely to transform rapidly simply as a result of evolving economics, but also to sectors where little attention has been devoted to emissions despite playing a growing role in the future. The latter sectors include off-road transport, where emissions come from a diffuse set of sources but where reductions could be realized at relatively low cost. When analyzing NZ50 results, it becomes clear that the difficulty of completely avoiding emissions from agricultural and industrial processes require dramatic and rapid reductions in energy-related emissions. Moreover, **energy-related emissions must present net negative emissions, achieved through all of drastic emission reductions, carbon capture applications, and the use of negative emission technologies**. While it would be difficult to understate this challenge, it underscores that the deployment of technologies already existing on a commercial scale or reasonably well developed should be planned quickly, which will also allow for the identification of gaps.

Furthermore, the importance of negative emissions applications in net-zero scenarios should be addressed rapidly, rather than be left for later as a last mile issue in net-zero trajectories. This requires a double track approach. First, the fact that most of these technologies do not currently exist at commercial scale, and that all are not currently deployed at a pace anywhere near what is implied by NZ50 results, should serve as a warning. The considerable uncertainties that still shroud their future use should be cleared up as rapidly as possible, so that their more precise role in the net-zero future can be determined sooner rather than later. Confirming the true cost of each technology and its realistic capture rate in practice, together with balancing electricity needs to operate DAC and for decarbonization throughout the economy, are high-level issues that must be part of this reflection. Second, so that failure to deliver negative emission applications at scale does not prevent moving toward net zero, it is essential, in parallel, to further develop low-emissions approaches for sectors that are difficult to decarbonize.

4.6 References

Langlois-Bertrand, S., K. Vaillancourt, O. Bahn, L. Beaumier, N. Mousseau. 2021. *Canadian Energy Outlook*. Institut de l'énergie Trottier and e3Hub https://iet.polymtl.ca/energy-outlook/

5

Provincial and territorial overview

Given that energy and GHG emissions profiles vary in important ways across provinces and territories, the evolution of each in the different scenarios presents distinct patterns. This profile diversity describes different opportunities to achieve GHG reduction targets in each province and territory. Accordingly, this chapter examines the evolution of the key components of provincial and territorial profiles on the way to net-zero, highlighting variations in the challenges each face.

To structure the overview and facilitate comparisons across provinces and territories, five questions are asked:

1. What are the main similarities and differences in energy consumption patterns across sectors?
2. How does primary and secondary energy production evolve in the province?
3. What is the extent of electrification and how does the electricity generation mix compare with the national average?
4. How does biomass production and use evolve?
5. How do the emissions trajectories compare to the national average?

In the modelling used in this report, NATEM optimizes the meeting of the net-zero constraint at the national level. As a result, net-zero scenarios do not imply that each province and territory achieve net-zero emissions on their own since it might be more cost-effective in some cases to leave emissions in certain parts of the country and move into net-negative regimes elsewhere to compensate.

Highlights

- Provincial and territorial diversity in current energy production and consumption patterns implies different challenges in participating in the national effort to reach net-zero emissions at lowest cost for the short and the longer term. Some provinces end up with net-positive emissions, while others find themselves removing more CO2 than they emit.
- Several important transformations are already underway, largely as a result of recently implemented federal policies; at the provincial level however GHG-reduction strategies are either absent or far less structuring, resulting in a much more limited transformative impact.
- Some specific applications like space heating in buildings can be decarbonized early on across all provinces.
- Even though many solutions are local or remain in the hands of the provinces, transportation should be viewed from a national perspective.
- Provinces and territories with a decarbonized electricity system and a small industrial sector must approach the costliest sectors (such as transport) early on; the opposite is true for those with emission-intensive industries (such as oil and gas production) or carbon-intensive power generation since emission reductions from these activities can all be achieved rapidly at relatively low cost.
- Provinces that currently have highly emission-intensive electricity generation and little hydroelectric baseload generation face more significant grid infrastructure development challenges; a national plan to support cross-provincial interconnections would facilitate the required transformation of electricity generation, especially for these provinces.
- Because of the high cost of transporting biomass, the availability of feedstocks in each province plays a large role in determining whether the results include BECCS electricity and/or hydrogen production in a specific province—and, as a result, the quantity of negative emissions for the province.
- Using a national target makes it possible to take advantage of some provinces' negative emissions to compensate for sectors more difficult to decarbonize in others.
- Given the lack of experience with negative emissions technologies at commercial scale, mapping out the potential of the different options is urgent to determine realistic expectations about their contribution to net-zero pathways across provinces.

5.1 British Columbia

1. What are the main similarities and differences in energy consumption patterns across sectors?

For buildings and industry, the evolution of energy consumption (Figure 5.1e) in British Columbia is similar to that at the national level. The energy mix is transformed toward a greater presence of electricity in industry and buildings. In the latter, electricity completely replaces fossil fuels in net-zero scenarios, with over 96% of energy consumption in 2050. As is the case nationally, this expansion of electricity is more modest in REF, where natural gas retains a share only slightly smaller than today by 2050.

Similarly to the national scenario, the road transport sector sees extensive electrification, with one notable difference in the net-zero scenarios being a more limited use of hydrogen. This is largely due to the province's smaller share of heavy-duty trucks, which are the main users of hydrogen. A larger portion of freight transport is therefore electrified since medium trucks convert overwhelmingly to electricity after 2040.

As a result of this pattern in the transport sector, British Columbia's hydrogen use is more limited than the national average. Hydrogen is used mainly in industry after 2040 in net-zero scenarios, while in REF only marginal quantities are used in road transport (<1 PJ in 2050).

Unlike at the national level, where total energy consumption declines by 10% in net-zero scenarios between now and 2050, energy consumption in British Columbia across all sectors except energy production remains essentially stable over this period. This stability is largely due to the relative importance of direct air capture operations in the province; almost one-third of energy consumption used across the country for DAC is in British Columbia. In 2050, the energy used to power DAC facilities amounts to 15% of the province's energy consumption outside of energy production, compared with only 6% at the national level.

2. How does primary and secondary energy production evolve in the province?

Contrary to the national average, natural gas production in British Columbia increases until 2040 in net-zero scenarios (Figure 5.1c). In NZ50, natural gas production grows continuously to 2040, reaching levels 62% higher than today at 3,600 PJ. However, this production drops by more than half in the following decade, declining to 1,700 PJ in 2050. This situation is quite different from that at the national level, where

Figure 5.1a – Total GHG emissions by sector – British Columbia

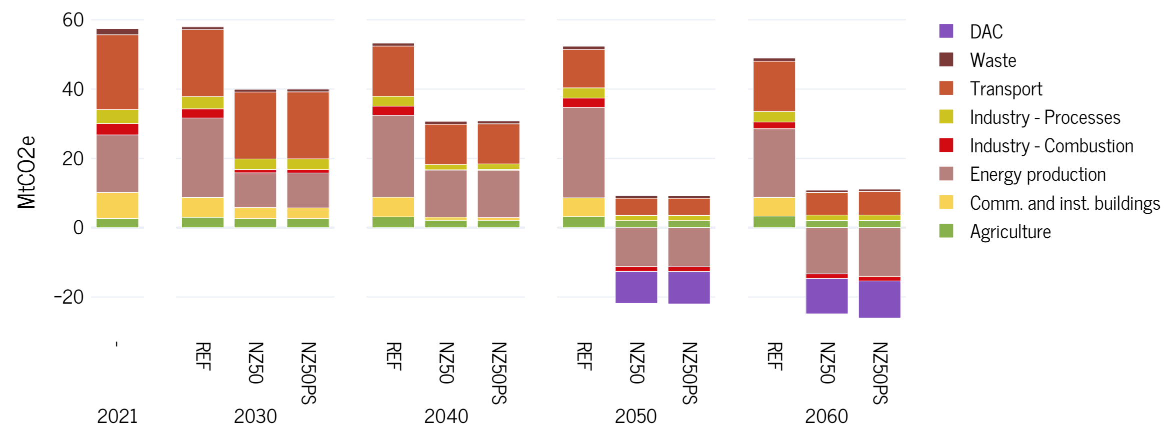
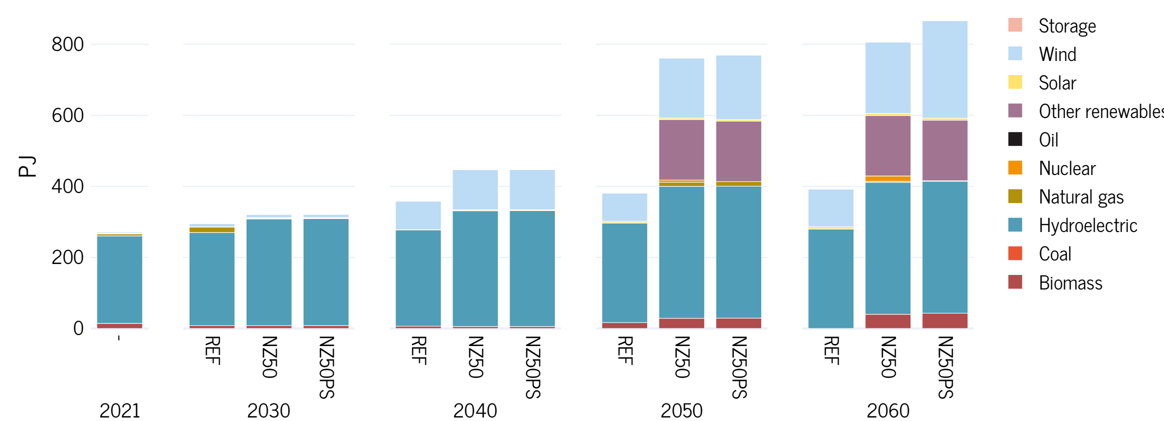


Figure 5.1b – Electricity generation by source – British Columbia



net-zero scenarios show a decrease in natural gas production even on the shorter term. Most natural gas produced in British Columbia, including in net-zero scenarios, is exported: as a result, GHG emissions remain limited to the operation used to produce the exported gas. These production emissions are reduced through regulatory constraints on methane emissions, making it possible to maintain higher production levels even in net-zero pathways.

While relatively small in absolute terms (250 PJ today), crude oil production triples to 2050 in REF but is virtually eliminated in net-zero scenarios (18 PJ in 2050).

Biomass feedstock production almost doubles by 2030, before being maintained at those levels over the rest of the time horizon. This is the case even in REF, unlike at the national level where the expansion is less significant in the reference scenario.

In sharp contrast to the national situation, there is no hydrogen production in REF. However, in net-zero scenarios, hydrogen production grows to 50 PJ in 2050 (Figure 5.1d), representing around 4% of all secondary energy production, which is lower than the national average (7%). This increase occurs only after 2040 and continues past 2050 as levels reach as high as 100 PJ in the NZ50PS scenario.

3. What is the extent of electrification and how does the electricity generation mix compare with the national average?

Similarly to the rest of the country, electricity consumption and production substantially increases in all scenarios in the province (Figure 5.1b). In REF, production in 2030 is 7% higher than today and 40% higher in 2050 (106 TWh). However, the contrast in net-zero scenarios is even more significant than at the national level: production grows 18% by 2030 (89 TWh) and almost triples by 2050, with levels around twice those of REF (210 TWh), in part to satisfy the rising direct air capture industry.

Contrary to the national portrait, very little nuclear generation is included in the electricity production mix in British Columbia, with only a small quantity of SMR generation in 2050 (1.7 TWh) and 2060 (4.2 TWh). Sources that underpin the growth in production include hydroelectric dams, which grow 19% to remain the most important source in the mix, and onshore wind, which rises to second place (56 TWh in 2060) from almost nothing today.

Figure 5.1c – Primary energy production – British Columbia

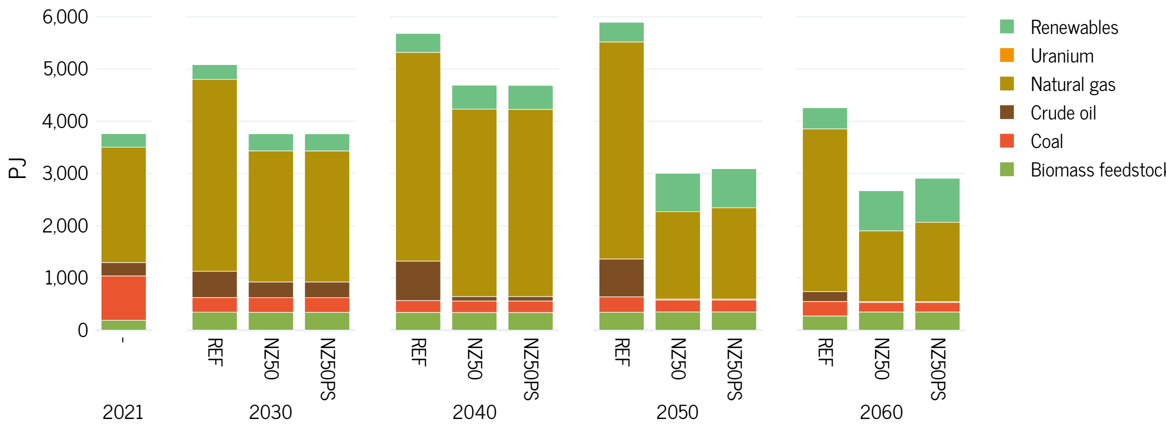
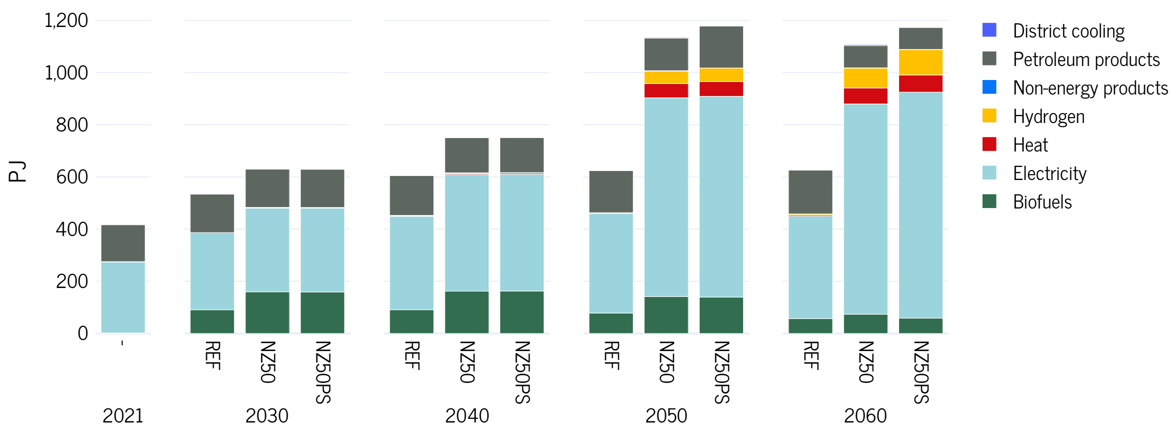


Figure 5.1d – Secondary energy production – British Columbia



Geothermal electricity production grows significantly more than the national rate: after 2040, this production takes off to reach 22% of the total (47 TWh) due to the province's considerable potential for cost-effective production. Given this baseload from hydro and geothermal, the need for SMRs or even storage remains small, with the latter supplying only 2 GW of the capacity mix (4%).

4. How does biomass production and use evolve?

While the overall quantity of biomass feedstock produced and used is similar over time for REF and NZ50, a key difference lies in the importance of wood biomass, which more than doubles in NZ50 by 2030 (Figure 5.1f). This quantity, corresponding to four times that seen in REF, is essentially used in the production of syngas and biochar, resulting in negative emissions. In REF, most of the increase in bioenergy is destined for tall oil production. Wood pellets exports are maintained to current levels in all scenarios (50 PJ), representing a little over half of Canadian wood pellet exports.

On the longer term, wood biomass is diverted away from various consumption points (including some syngas and biochar production, pulp and paper, and other manufacturing operations) to BECCS electricity production, contributing to the increase in electricity production while resulting in negative emissions. This occurs after 2040 and a small quantity also serves for hydrogen production through BECCS gasification.

Wood biomass is the only source of biochar in the province since all agricultural residues are used for a very small BECCS electricity production (2 PJ). This is quite different from the national average, where most agricultural residues are used for biochar; but even more importantly, the use of agricultural residues for energy purposes is almost non-existent in British Columbia, as these 2 PJ compare with 580 PJ at the national level.

Figure 5.1e – Final energy consumption by sector – British Columbia

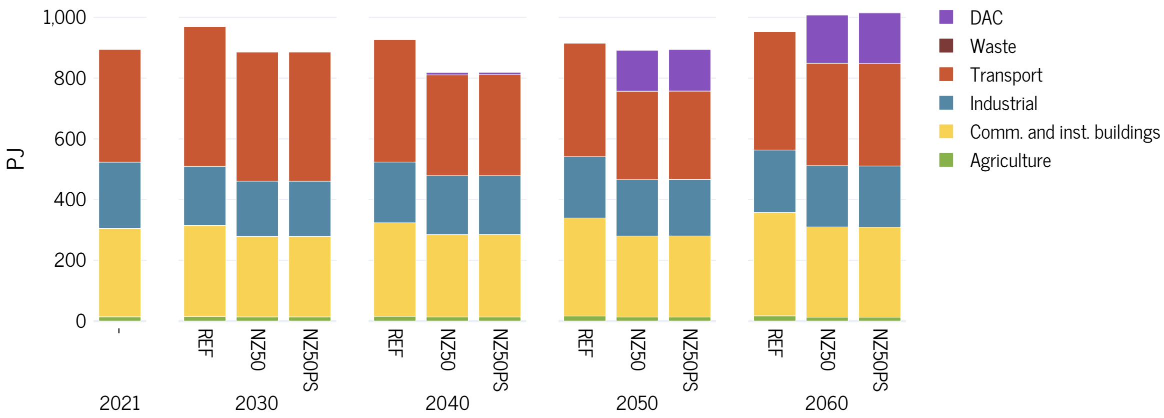
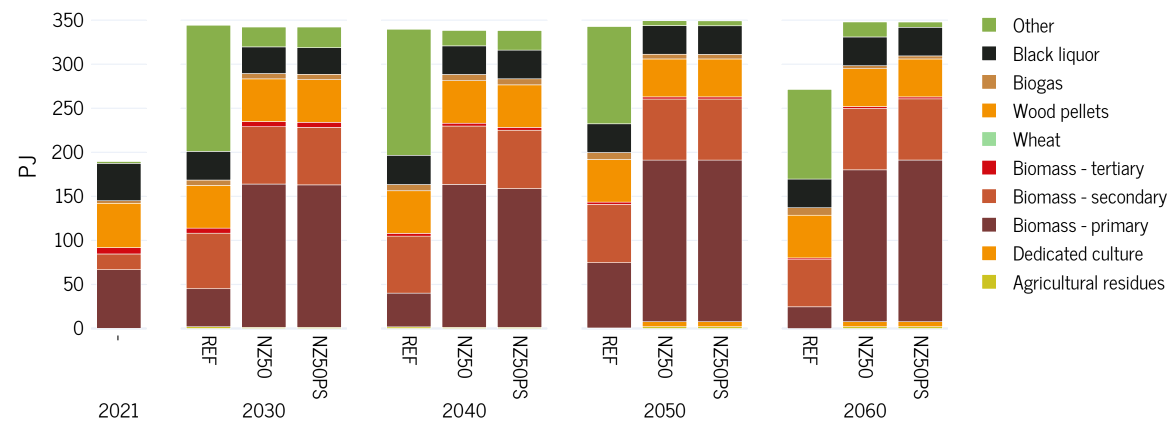


Figure 5.1f – Biomass feedstock used by type – British Columbia



5. How do the emissions trajectories compare to the national average?

In REF, emissions in British Columbia decline by only 10% by 2050, a significantly smaller relative reduction than the national average (-20%). This is largely because electricity production is already decarbonized in the province, whereas it constitutes a significant source of GHG reductions over time at the national level.

Furthermore, the net-zero scenarios yield a large quantity of negative emissions in the province (Figure 5.1a), reaching a net negative total of -13 $MtCO_2e$ in 2050, or 21% of BC's current emissions (61 $Mt.CO_2e$). This is a direct result of the extensive use of BECCS processes for electricity and hydrogen production, biochar production and DAC. In the latter case, around a quarter of national emissions captured from DAC is achieved in British Columbia.

This is by far the largest net negative total in any province, making British Columbia a key contributor to the net-zero target at the national level. The province's readily available wood biomass feedstock enables lower-cost BECCS production, making it more cost-effective from a national perspective to overshoot the net-zero target in British Columbia to compensate for more significant remaining emissions in provinces where these options are more costly.

Bottom line: how does British Columbia stand out from other provinces in the results?

Based on the above results, a few key differences between British Columbia and the national average emerge:

- The province contributes a significant amount of net negative emissions to the national total.
- The electricity mix does not rely heavily on nuclear SMRs, taking advantage instead of geothermal and additional hydro facilities.
- Natural gas production does not decrease as abruptly as at the national level in net-zero scenarios.
- Forest biomass resources are used to supply BECCS electricity and hydrogen production as one of the main sources of negative emissions.
- Consumption in the freight transport sector makes more modest use of hydrogen, in large part due to the relatively small proportion of heavy trucks in the province's transportation sector.

5.2 Alberta

1. What are the main similarities and differences in energy consumption patterns across sectors?

In the REF scenario, energy consumption in Alberta (Figure 5.2e) increases more rapidly than it does at the national level. In net-zero scenarios, total energy consumption evolves similarly to the national average: consumption rises by 2030 before declining until 2050, reflecting the efficiency gains from the electrification of many services. After 2050, consumption then increases again as electrification is largely completed and the population and GDP continue to grow.

Due to the large share of natural gas in buildings today (70%), the gain from changes in the energy mix in the sector reduces total energy consumption over time more than the national average. By 2050, consumption is down 38% from today (280 PJ) in NZ50. The transformations to the mix are also different than elsewhere in the country: while electricity comes to play a much larger role (62% of the total in 2050), this expansion is more modest, rising only 58% over today's levels (compared with a 32% increase of electricity in REF). Instead, district heating expands to a 12% share by 2050, while thermal solar (15%) and syngas (6%) provide most of the rest for 2050. Once hydrogen production increases after 2040, a H2 blend also plays a similar role to syngas.

Energy consumption in industry increases over time in both REF and NZ50. By 2050, this increase is 40% higher in REF and 24% higher in NZ50 than today's levels. The drivers of this increase differ depending on the scenario: in REF, the change derives overwhelmingly from more natural gas consumption; in NZ50, in contrast, bioenergy use triples to 100 PJ, electricity almost triples to 140 PJ, and hydrogen use climbs by 250% to reach 170 PJ in 2050. This contrast is not explained by the province's different industrial make-up, but rather by technological transformations that allow fuel substitution. Most industrial subsectors evolve similarly in REF and in NZ50, with total energy consumed being 11% lower in NZ50 due to efficiency gains.

Freight road transport occupies a larger share of energy consumption in transport in Alberta, with 46% of the total for the sector, compared with 32% at the national level. In net-zero scenarios, this subsector is significantly transformed in the province, resulting in a decline of 55% of its energy use by 2050. The energy mix is similar to that on the national level, with hydrogen powering most heavy trucks, along with a smaller share for catenary, and battery-electric vehicles meeting the rest of the needs for freight and passenger transport.

Figure 5.2a – Total GHG emissions by sector – Alberta

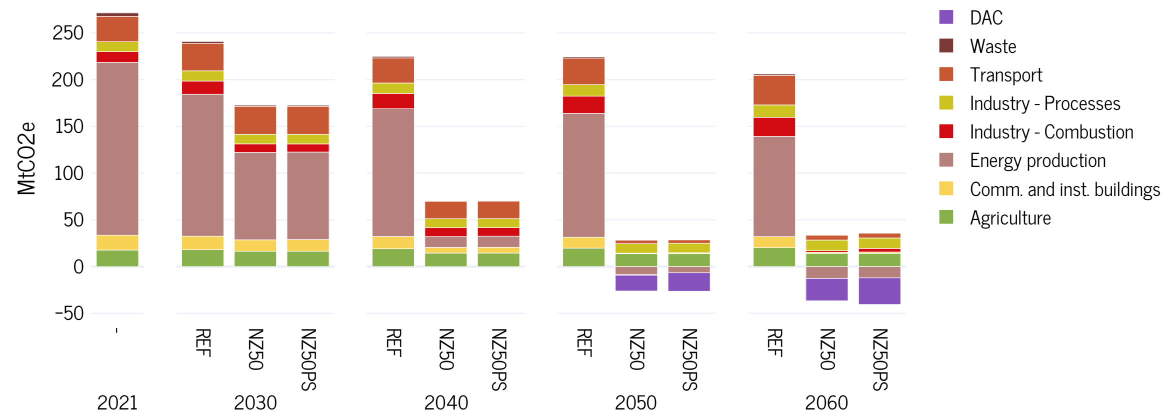
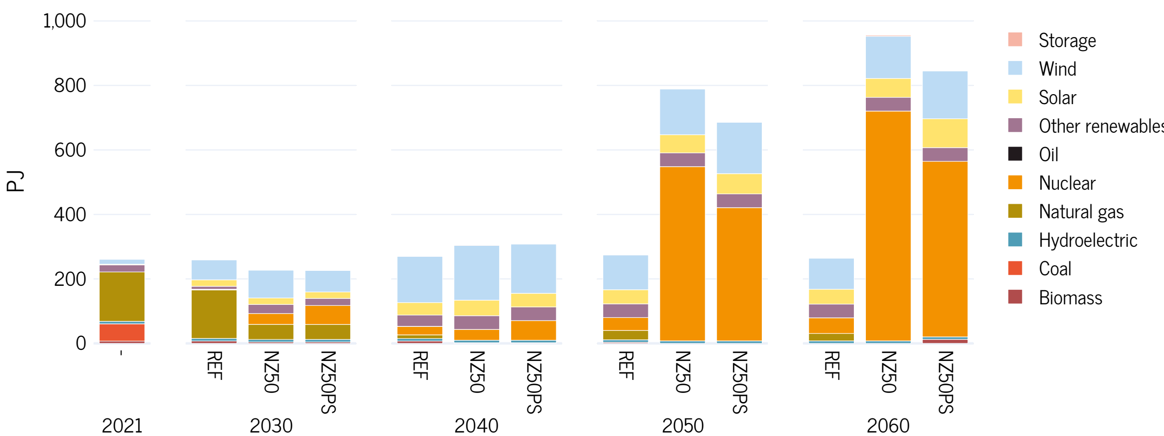


Figure 5.2b – Electricity generation by source – Alberta



As in British Columbia, the use of DAC around and after 2050 takes a bigger toll on energy consumption in Alberta compared with the national average. DAC energy consumption amounts to 10% of total final energy consumption across sectors outside of energy production, compared with 6% at the national level.

2. How does primary and secondary energy production evolve in the province?

The pattern of the evolution of primary energy production (Figure 5.2c) in Alberta is different than that of the national average. In net-zero scenarios, electricity production expansion involves a relatively small share of renewables, and most of it is secondary production comes from nuclear SMRs. Therefore, the distinction between primary energy production in Alberta and at the national level over time is very sharp: crude oil production falls rapidly in NZ50, with an 84% reduction before 2040 and 92% before 2050. In REF, levels increase by 16% on the short term and remain at similar levels throughout 2050, before declining 27% in 2060 due to lower international demand projections.

Owing in part to these lower projections, natural gas production falls by more than 50% by 2030 in both REF and NZ50. Production rebounds after 2030 in REF, almost doubling by 2050, while in NZ50, levels continue to decline rapidly, ending at less than 10% of today's output in 2050. This results in a virtual elimination of oil and gas exports from Alberta, although export routes from Alberta production centres to Saskatchewan and Manitoba gas export pipelines continue to be used.

In relative terms, biomass feedstock production increases more significantly than in British Columbia. From 90 PJ today, production climbs to 150 PJ by 2030 in REF and to 320 PJ in NZ50; it then remains at similar levels for the rest of the time horizon, as is the case elsewhere in the country.

Hydrogen production remains at current levels in REF (Figure 5.2d), in sharp contrast to the national picture, essentially due to the large reduction in the level of the natural gas production. The picture is quite different in net-zero scenarios: hydrogen production more than doubles to 110 PJ by 2040 and increases to 240 PJ in 2050 and 320 PJ in 2060. This contributes some third of the national total for NZ50, with CCS-equipped autothermal reforming installations providing the bulk of the production before 2050 and BECCS production helping from 2050.

Figure 5.2c – Primary energy production – Alberta

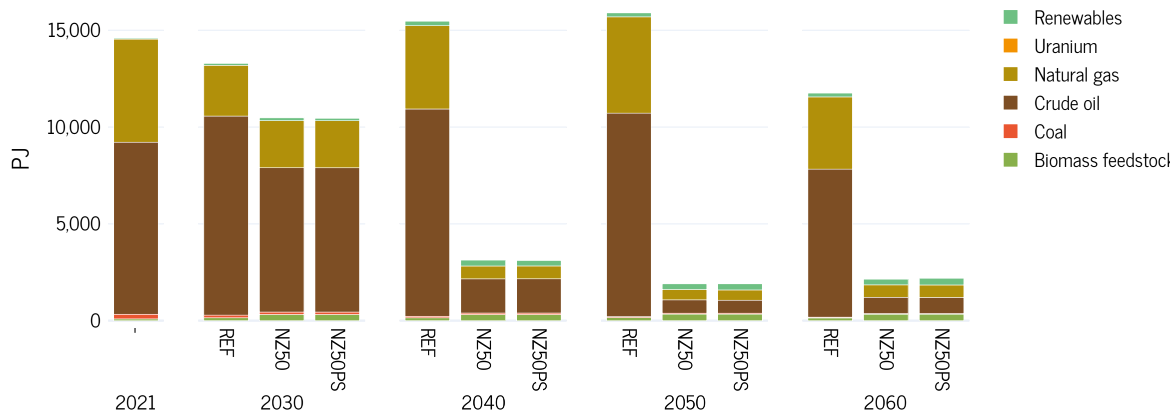
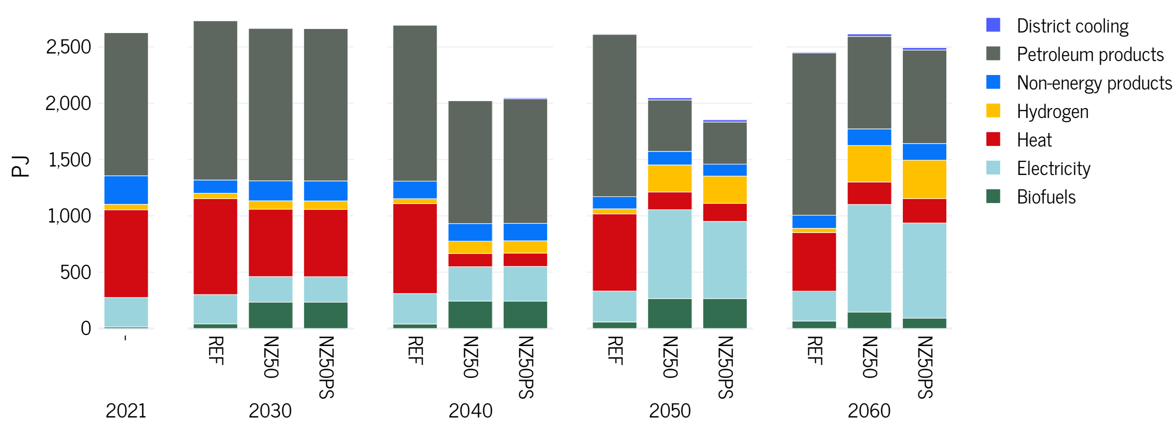


Figure 5.2d – Secondary energy production – Alberta



3. What is the extent of electrification and how does the electricity generation mix compare with the national average?

In net-zero scenarios, electricity production (Figure 5.2b) in Alberta triples by 2050 (to 220 TWh) outpacing growth in demand (+154%), in sharp contrast to REF, where this production remains more or less constant for the entire time horizon, despite demand increasing by 38% before 2050 in REF. It directly follows that net imports of electricity become a key source for Alberta over time in REF, but this is also the case in NZ50.

In NZ50, virtually all the increase occurs past 2040, mainly due to nuclear SMRs becoming by far the largest source of production, a buildout that only occurs after 2040. A small number of SMRs already appear by 2030 (totalling between 1 and 2 GW in net-zero scenarios), before taking off in the 2040s to reach 19 GW in 2050 and 25 GW in 2060.

While SMRs come to produce around 68% of electricity in Alberta from 2050, other sources also expand significantly since a tripling of production in net-zero scenarios also implies a replacement of most existing generation capacity. Natural gas production disappears in net-zero scenarios in the 2030s as the CER comes into effect and no CCS-equipped facility emerges as a cost-effective alternative.

Wind is the other technology that sees a spectacular expansion. Wind production is multiplied by 10 by 2040 (170 PJ) before returning to 140 PJ in 2050 as SMRs emerge to play a larger role. Geothermal doubles to 42 PJ by 2040, while centralized solar expands to 50 PJ.

Given the size of the SMR production, less than 2 GW of storage is installed in net-zero scenarios. This is not much more than in the REF scenario, which installs similar quantities. In the more pessimistic SMR scenario, SMRs emerge strongly nonetheless and centralized solar and onshore wind compensate the smaller quantity of nuclear generation.

4. How does biomass production and use evolve?

The overall quantity of biomass feedstock develops similarly to the national average: REF sees levels increase by 60% before 2030 (150 PJ) and NZ50 levels reach twice that size at 320 PJ, after which both scenarios remain at comparable levels through 2060. The difference between REF and net-zero scenarios is mainly owing to the use of a large quantity of agricultural residues (150 PJ) with a greater use of wood biomass (150 PJ) as well in NZ50 (Figure 5.2f).

Figure 5.2e – Final energy consumption by sector – Alberta

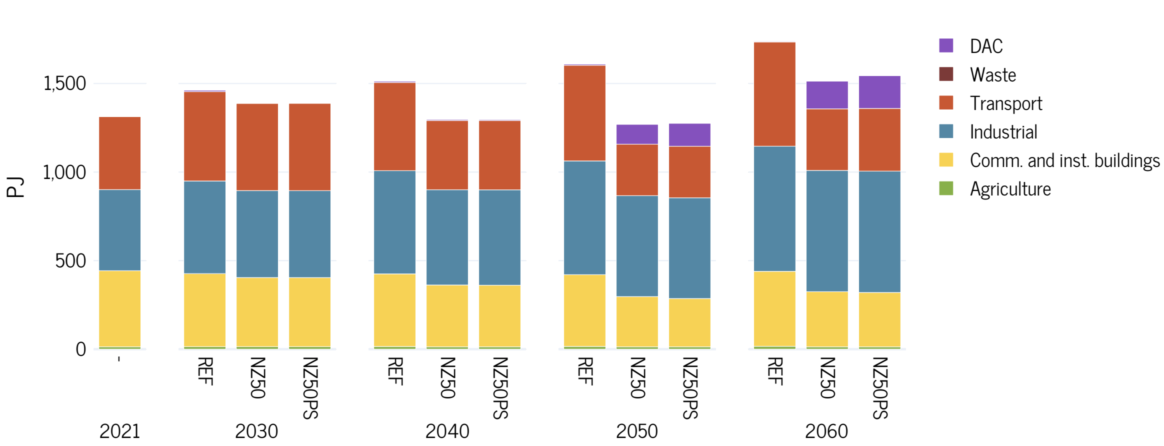
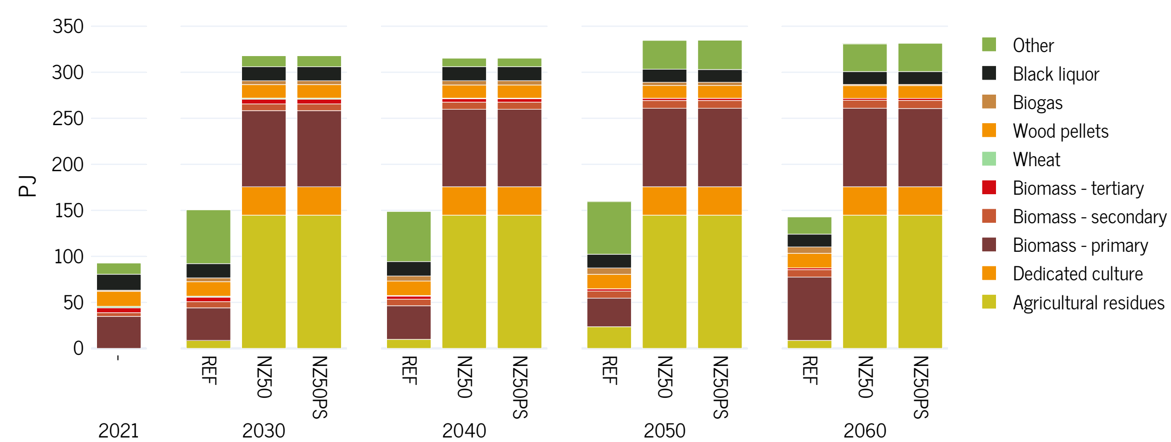


Figure 5.2f – Biomass feedstock used by type – Alberta



Before 2050, almost all agricultural residues are used to produce syngas and biochar, resulting in negative emissions. Once hydrogen demand increases, some of this use is diverted toward BECCS hydrogen production, reaching 90 PJ in 2060, the rest going to biochar. A similar pattern occurs for wood biomass, more than 77% of which serves to produce biochar and syngas by 2050, after which BECCS hydrogen production takes a 31% share.

5. How do the emission trajectories compare to the national average?

Despite drastically reduced fossil fuels production, a large amount of emissions remains at the net-zero point in Alberta (Figure 5.2a). These emissions derive mainly from agriculture (14 $MtCO_2e$ in 2050, down from 18 today and much less than the 20 in REF) and industrial processes (10 $MtCO_2e$ in 2050, similar to today and only slightly lower than REF). Otherwise, following trajectories similar to those on the national scene, industry (combustion) achieves net negative emissions and transportation cuts emissions by over 80% before 2050. One important distinction is the size of the cuts in emissions from energy production, falling from 190 $MtCO_2e$ today to 0 in the early 2040s, owing not only to the drastic cuts in oil and gas production but also to the application of some CCS (9 $MtCO_2e$ captured in 2040).

After 2040, the energy production sector results in negative emissions (-9 $MtCO_2e$ in 2050 and -13 in 2060). A large portion of this is due to BECCS hydrogen production (-11 $MtCO_2e$ in 2060), although the contribution of capture operations is not limited to BECCS: in both 2050 and 2060, 16 $MtCO_2e$ of CCS is used in industry and hydrogen production (outside of BECCS) to bring down the province's total emissions. Despite this, an additional -5 to -10 $MtCO_2e$ from biochar is also necessary, in addition to a considerable quantity of DAC (-17 $MtCO_2e$ in 2050 and -24 in 2060, roughly half the national total). This brings the total of captured emissions stored to 40 $MtCO_2e$ in 2050, in addition to the 10 $MtCO_2e$ in biochar.

In the end, Alberta remains net positive in terms of GHG emissions in net-zero scenarios, with 3 $MtCO_2e$ remaining in 2050 and 2060. This is nevertheless a drastic departure from today's emissions profile for the province (270 $MtCO_2e$).

Bottom line: how does Alberta stand out from other provinces in the results?

Based on the above results, a few key differences between Alberta and the national average emerge:

- Net-zero scenarios impose very significant transformations in the province's sectors, the first and foremost being energy production.
- This is not the only pattern that differs from the national average as both buildings (given the large role played today by natural gas) and electricity production require significant transformations.
- The transformations to electricity production are more substantial than anywhere else in the country, requiring both a massive increase in quantity (tripling current levels by 2050) and a replacement of current capacity from natural gas to meet the CER requirements; this comes in addition to SMRs playing a fundamental role in the mix due to limited alternatives for baseload electricity production and the high estimated cost of producing electricity with gas power plants equipped with CCS infrastructures.
- The province's use of capture in general, and negative emissions in particular, is extensive, including DAC at levels higher than the national average, yet some emissions still remain.

5.3 Saskatchewan

1. What are the main similarities and differences in energy consumption patterns across sectors?

Contrary to the national average, final energy consumption across sectors (Figure 5.3e) grows for the entire period in Saskatchewan in the reference scenario, resulting in 23% more energy used in 2050 (from 410 to 500 PJ), despite efficiency gains from electrification and other expected transformations. NZ50 consumption decreases after 2030 and remains well under REF levels even in 2050 (410 PJ) and 2060 (490 PJ) once direct air capture consumption grows to 13-17% of the total.

This growth in consumption in REF is largely the result of a contrast between expectations for the transportation and industrial sectors. In the province's transport sector, which represents more than 50% of total energy consumption, needs grow from 210 to 270 PJ (+31%) to 2050, while they remain roughly stable at the national level. Growth to 2050 for off-road (+34%) and road freight (+68%) is much more significant than in the national portrait, explaining the contrast in REF. While reductions in NZ50 are substantial (-36% for road freight), they are still more modest than the national average (-54%). This is especially noteworthy as road freight occupies a larger share of final energy consumption in Saskatchewan (37% today) than the national average (32%), underlining the importance of the sector in efforts to aim for net-zero.

Like Alberta, Saskatchewan uses natural gas for a larger share of its energy needs in buildings (66%) than the national average (49%). Efficiency measures and a small growth in electricity bring this share down to 50% in 2050 in REF, while in NZ50 natural gas is rapidly eliminated from buildings. Electricity accounts for most of the replacement, although small contributions from a number of other sources (district heating, geothermal, thermal solar and syngas) also combine for 12% of the mix in 2050.

The energy mix used in industry grows 48% by 2050 in REF, from 90 to 130 PJ, driven primarily by natural gas. NZ50 increases are more limited but still substantial (36% by 2050, to 120 PJ). However, the mix undergoes a transformation in NZ50 where natural gas' share shrinks to 2% of the total (from 25% today), while electricity and hydrogen both double their current levels in 2050 to 70 PJ (55% of the total) and 20 PJ (17%) respectively. The drivers of increased overall demand are mainly in the mining sector, which increases its energy consumption by 73% in 2050 in all scenarios, and pulp and paper, which more than doubles its consumption as well.

Figure 5.3a – Total GHG emissions by sector – Saskatchewan

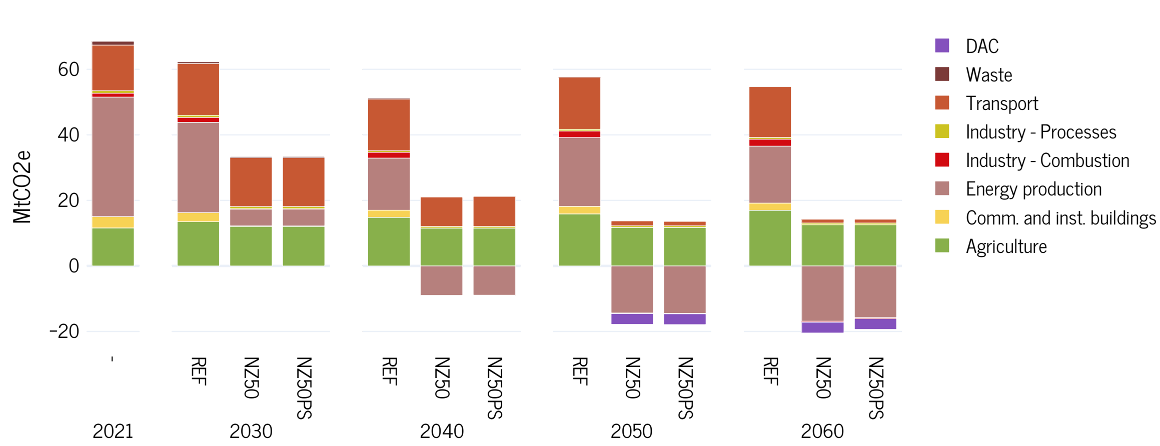
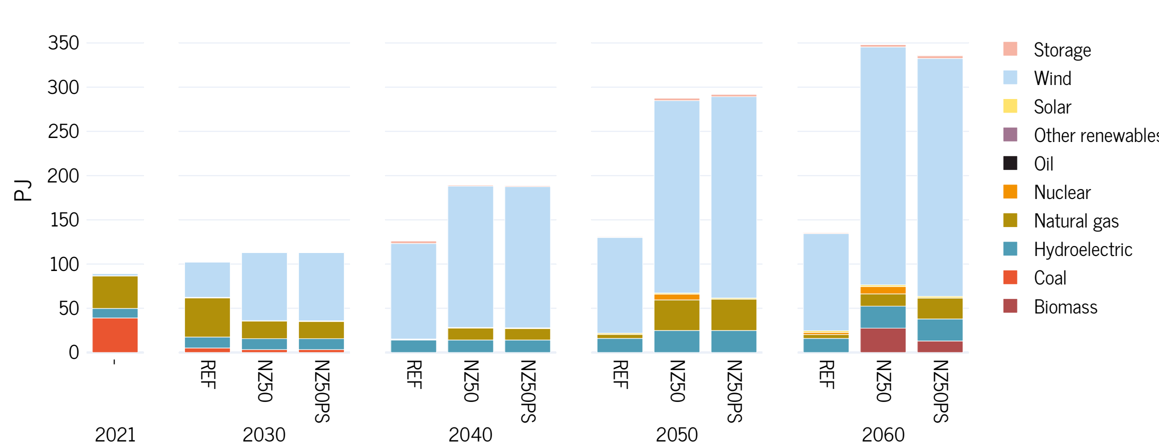


Figure 5.3b – Electricity generation by source – Saskatchewan



2. How does primary and secondary energy production evolve in the province?

Measured by energy content, the largest primary energy production sector in Saskatchewan is by far uranium (Figure 5.3c), with crude oil production being the other notable sector (14% of the total). Until 2060, these percentages do not change: REF shows more or less constant production levels for both these sources throughout 2060, with wind electricity production emerging in small quantities comparatively (110 PJ in 2050), while today's modest natural gas and coal production is eliminated by 2050.

In NZ50, crude oil production declines by 90%, in contrast to uranium production, which increases by 33% by 2050. Wind electricity also emerges but more significantly than in REF, reaching around twice the levels in the reference scenario in 2050 (220 PJ).

It should be noted that demand for uranium exports is flat for the entire time horizon in both REF and NZ50. As a result, exports remain the same in the results for all scenarios, which means that the higher production levels in NZ50 are driven by the larger domestic demand for nuclear electricity production. Natural gas exports, which result from pipeline imports from Alberta as well as a small production in Saskatchewan, drop 76% by 2050 (to 210 PJ) in all scenarios, reflecting lower global demand projections and larger domestic demand in REF.

While biomass feedstock production increases from 14 PJ to 24 PJ in REF, NZ50 levels are drastically larger from 2030 (280 PJ), mainly as a result of an increase in agricultural residues. Hydrogen production remains limited in REF as well as in net-zero scenarios (Figure 5.3d), with 70 PJ produced at its peak in 2060 for NZ50. These levels are quite different from the national average, where hydrogen production increased by a factor of 10 in net-zero scenarios.

3. What is the extent of electrification and how does the electricity generation mix compare with the national average?

Electricity production in Saskatchewan (Figure 5.3b) increases 46% in REF by 2050, from 25 to 36 TWh or 89 to 130 PJ), following demand projections from expected trends in electrification. This is nevertheless a much smaller modification than in NZ50, where generation more than triples by 2050 (to 80 TWh).

Aside from the total quantities produced, the generation mix sees relatively similar changes in REF and NZ50: wind is by far the main driver of the increase, making up 82% of generation in REF and 75% in NZ50 in 2050. Although a small share of the total (2.5 TWh) today, hydro-

Figure 5.3c – Primary energy production – Saskatchewan

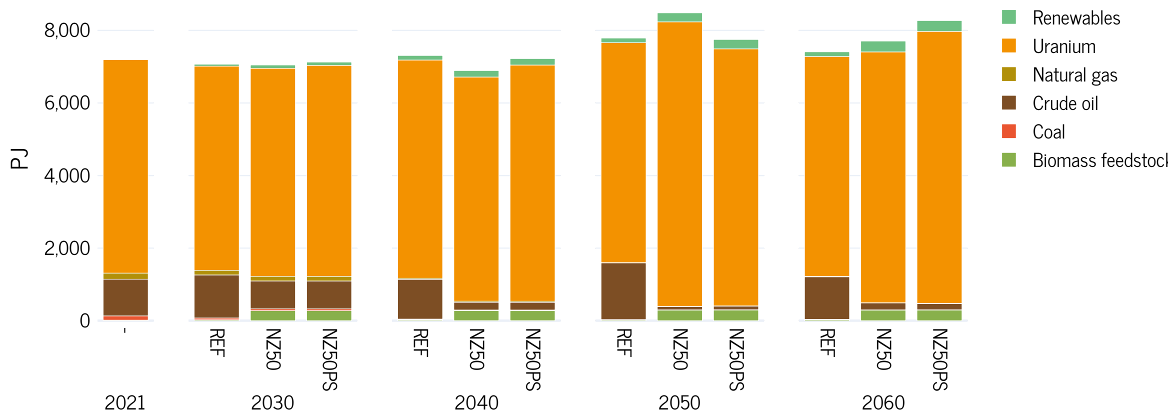
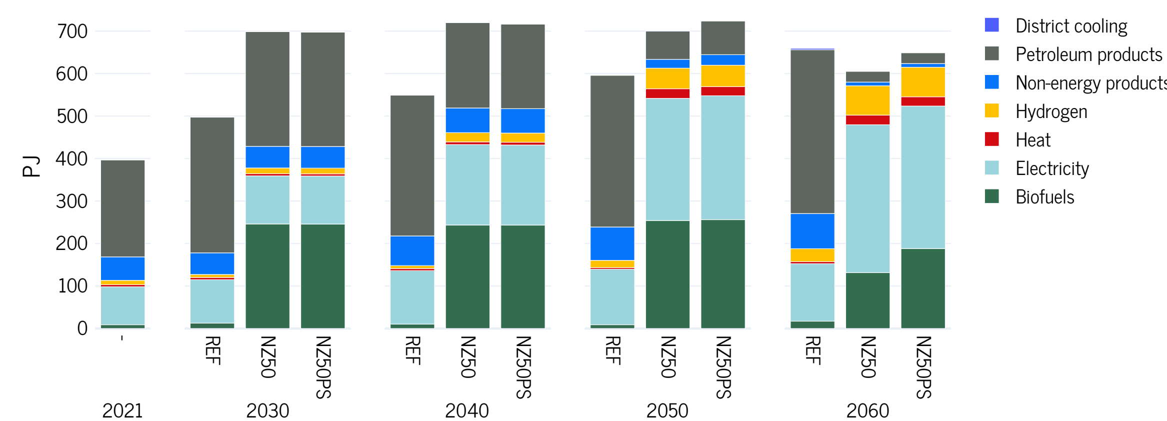


Figure 5.3d – Secondary energy production – Saskatchewan



electric dams also increase by close to 50% in REF and by 150% in NZ50. Coal-fired generation is completely eliminated in all scenarios as a result of the implementation of the CER in 2035.

One of the only marked differences between REF and NZ50 is in natural gas-fired generation: in REF natural gas in CCS-equipped facilities is maintained as a backup, while in NZ50 it comes to supply more than 10% of the total electricity. Nuclear SMRs also emerge only in NZ50, although in very small quantities, with only 220 MW of capacity installed in 2050. This reduced role for SMRs is partly due to the more limited possibilities for recovering waste heat in SMR power plants in Saskatchewan than in Alberta and Ontario, where this recovery reduces the overall cost of this generation on a total energy production basis.

Given the large share of wind, several storage options emerge in the capacity mix, including batteries and pumped hydro, each within 2 GW of capacity installed in 2050.

4. How does biomass production and use evolve?

Net-zero scenarios use much larger quantities of biomass (Figure 5.3f), climbing from 14 PJ today to 280 PJ in 2030, a level that remains roughly stable until 2060. Most of this is in the form of agricultural residues (220 PJ in 2030), which are all destined for syngas and biochar production from 2030. Once 2050 is reached, the total quantity used remains the same, although almost two-thirds are diverted to BECCS electricity and hydrogen production, taking the opportunity to contribute to meeting higher demand for both these forms of energy in the 2050s, while maintaining the side benefit of negative emissions.

Wood biomass increases from almost nothing today to 50 PJ in 2030, with half deriving from dedicated crops. All this feedstock goes into syngas and biochar production, with a small amount transferred to hydrogen production from 2050.

Figure 5.3e – Final energy consumption by sector – Saskatchewan

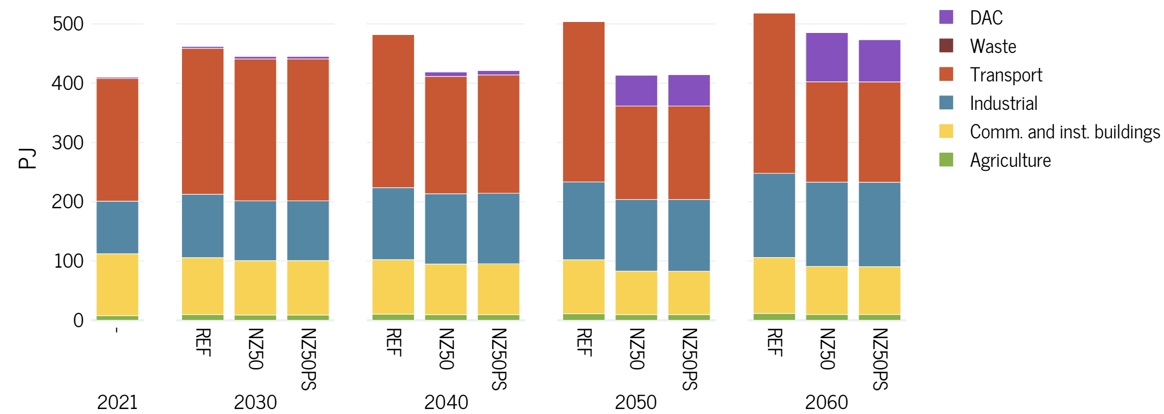
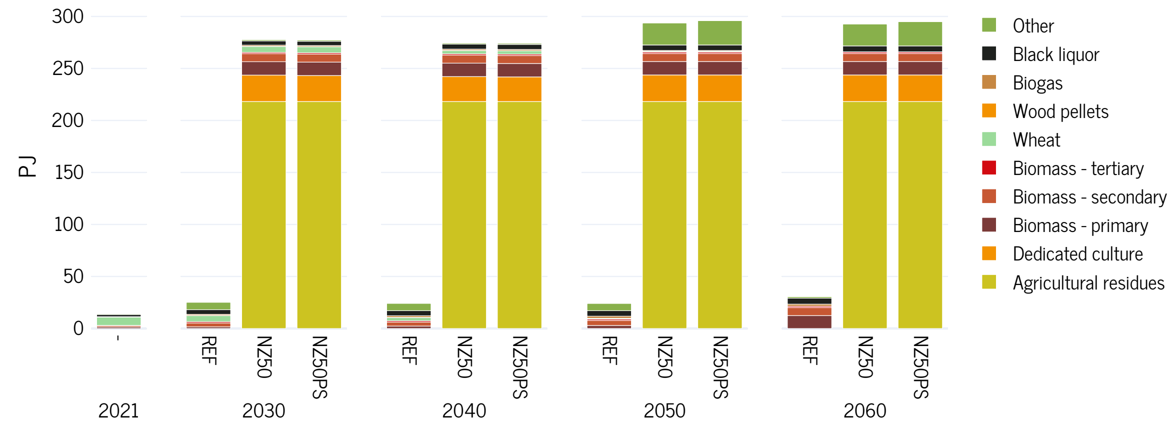


Figure 5.3f – Biomass feedstock used by type – Saskatchewan



5. How do emissions trajectories compare to the national average?

Remaining emissions at the net-zero point for Saskatchewan (Figure 5.3a) come mainly from the province's very large agriculture sector, with emissions staying at levels similar to those of today in 2050 (12 $MtCO_2e$). A small quantity of emissions from transport also remains (2 $MtCO_2e$). Given the province's small industrial base outside energy production, today's emissions for the sector are relatively modest. Nevertheless, they are brought close to net-zero for the sector, even when process emissions are included, a result of an almost complete elimination of natural gas as a source for combustion and a reduction in emissions from halocarbons production.

Saskatchewan's energy production sector manages to be net negative (-14 $MtCO_2e$ in 2050). Similarly to other provinces, there is a pattern that makes biochar the main source of negative emissions throughout 2050, before declining in importance as BECCS production becomes more significant. This is mainly for electricity generation, with some BECCS renewable gas and hydrogen production as well.

The province subtracts around 3 $MtCO_2e$ from the bottom line through direct air capture, making its total net negative (between -4 and -6 $MtCO_2e$). Like the situation in British Columbia, this means a contribution to the national net-zero target that allows larger amounts of remaining emissions in other provinces where they may be more costly to eliminate.

Bottom line: how does Saskatchewan stand out from other provinces in the results?

Based on the above results, a few key differences between Saskatchewan and the national average emerge:

- Energy consumption grows in each decade in REF, contrary to the national average.
- NZ50 energy consumption declines less significantly than the national average as emissions in freight transport and off-road show more modest reductions, and industry consumption, driven by expanded mining, increases 36%.
- Uranium production increases in NZ50 as export levels are kept constant (and comparable with REF), while domestic demand for nuclear generation requires more of the fuel. This is a limitation in the scenario; as better information on worldwide uranium demand becomes available in the next few years, these results may change.
- Biomass resources are tapped into in much greater quantities than today, making use of available agricultural residues in particular in negative emissions applications.
- The province is ultimately net negative since DAC and other net negative emissions activities combine to more than offset the remaining emissions elsewhere.

5.4 Manitoba

1. What are the main similarities and differences in energy consumption patterns across sectors?

The pattern of total final energy consumption in Manitoba (Figure 5.4e) evolves similarly to the national average in REF, with a short-term 15% increase by 2030, a trend that is turned around by efficiency gains (including through electrification of transport and buildings), resulting in a plateau until the 2050s. Upward pressure on demand from population growth then continues to drive an increase in overall demand; further efficiency gains and technological substitution are too expensive to be expected without additional policy measures.

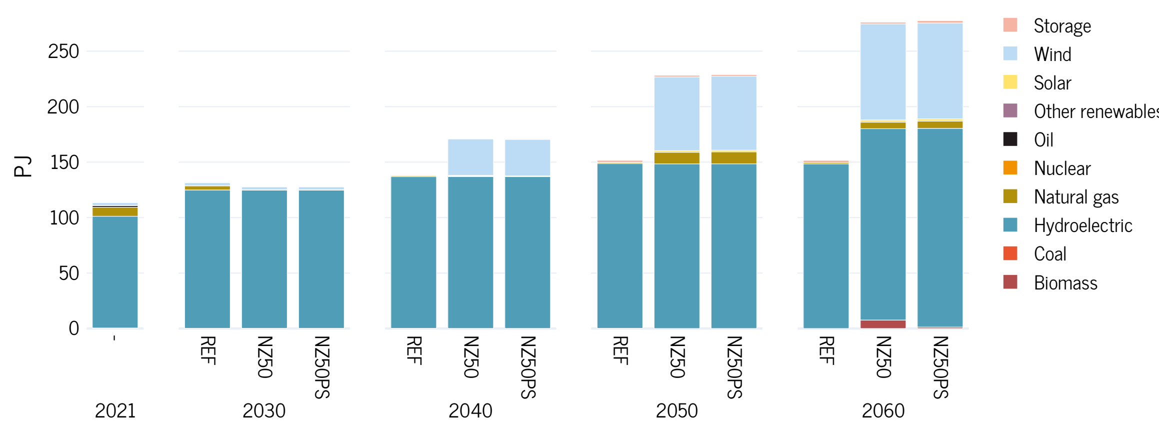
Due to NZ50's more aggressive decarbonization, the increase in demand to 2030 is more modest and more efficiency gains follow, resulting in consumption levels in 2050 similar to those of today (280 PJ). In REF, the rebound after 2050 is also important, although a large share of the increase derives from the energy used to power DAC operations.

The energy mix in buildings follows the national trend: while natural gas and electricity each currently supply about half the consumption in buildings for the province, which is similar to the national mix, electricity takes shares away from natural gas to reach 73% of the total in 2050 in REF. In NZ50, natural gas is rapidly retired until none remains in 2040, with electricity expanding more significantly and geothermal and district heating supplying less than 5% of the total as well. Also similar to the national average is the temporary role of syngas, which comes to represent 13% in 2030 and 2040 before declining in 2050. In NZ50, overall consumption is 17% lower in 2050 compared to today, as a result of the increased effectiveness of the mix and cumulative energy efficiency improvements.

In industry, electricity grows to supply 50% of the mix in Manitoba in 2050, representing a more significant increase than the national average (39%). The remaining changes across scenarios are similar to those observed nationwide: the main difference between REF and NZ50 is the importance of natural gas, which remains high in REF but decreases abruptly in NZ50, supplying only 5% of the mix in 2050. Both hydrogen and bioenergy increase more substantially in NZ50 than in REF where they remain at levels similar to those today.

Figure 5.4a – Total GHG emissions by sector – Manitoba

Figure 5.4b – Electricity generation by source – Manitoba



Consumption in transport increases by 28% before 2050 in REF as the electrification of passenger transport compensates increases in off-road (+96%) and road freight transport (+63%) which are both greater than the national average. NZ50 increases consumption less in off-road (+50%), while completely inverting the trend in road freight transport (-22%), mainly through the increased efficiency gained from switching to hydrogen and electricity in road and rail, thus eliminating oil products. Rail also switches part of its operations from diesel to electricity.

Energy consumption for DAC occupies a larger than the national average share of overall consumption in Manitoba. This is especially the case in 2060, when it reaches 11% of total final energy consumption, compared to 7% nationwide.

2. How does primary and secondary energy production evolve in the province?

Primary energy production (Figure 5.4c) is very limited in Manitoba (200 PJ in total today). Apart from a small amount of crude oil production (80 PJ), which disappears in NZ50 but not in REF, the rest of today's production consists mainly of hydroelectricity (100 PJ) and a small quantity of biomass feedstock (14 PJ). In NZ50, biomass feedstock production expands to 100 PJ in 2030 and renewable electricity production more than doubles to 2050.

The province's secondary energy production is also limited (Figure 5.4d), with only hydrogen increasing over time, from 7 PJ today to 13 PJ in REF and 38 in NZ50, although most of the increase in the latter scenario occurs past 2050. District heating also emerges only in NZ50, reaching 14 PJ.

Figure 5.4c – Primary energy production – Manitoba

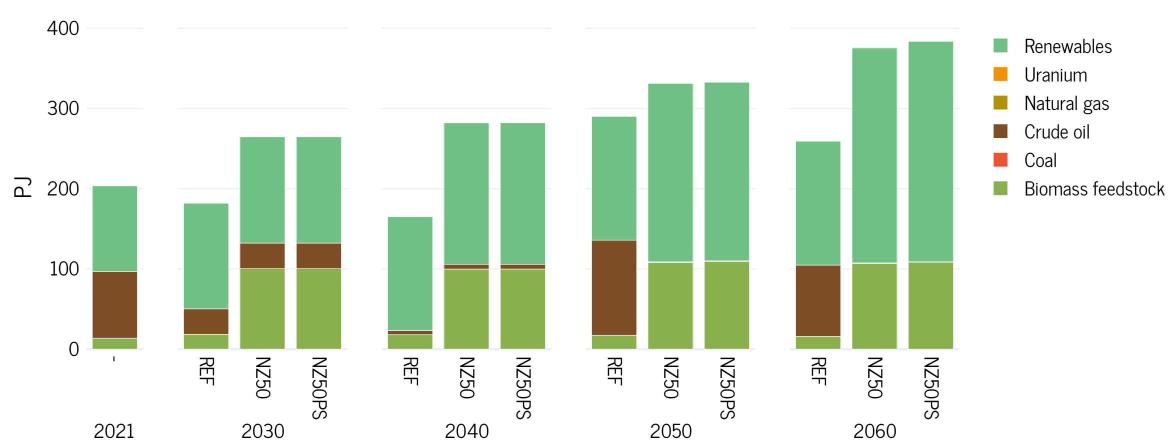
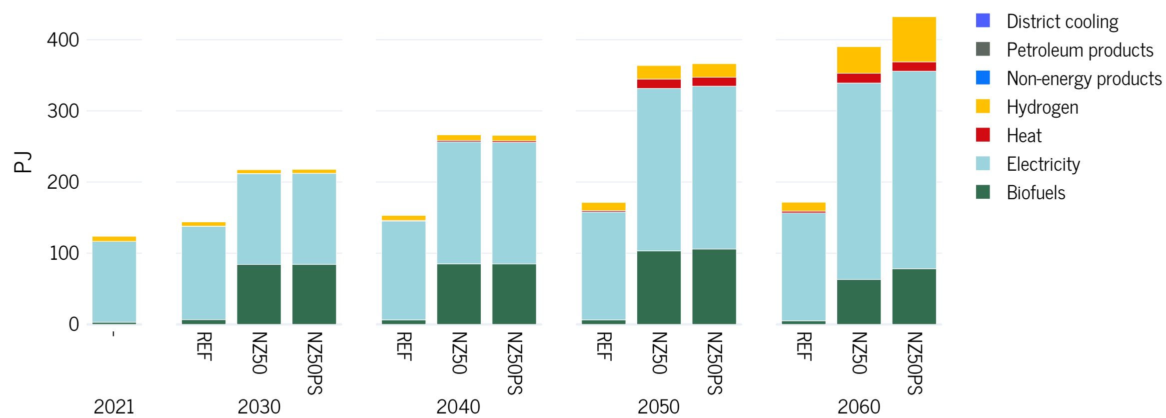


Figure 5.4d – Secondary energy production – Manitoba



3. What is the extent of electrification and how does the electricity generation mix compare with the national average?

As mentioned above, in NZ50 electricity production doubles in Manitoba before 2050, compared to a 33% increase in REF over the same period (Figure 5.4b). Since production is already decarbonized in the province, this change chiefly involves expansion of existing renewable sources. Hydroelectricity (through both dams and run-of-river facilities) grows 47% in both REF and NZ50, reflecting the relative low-cost of untapped hydro potential for meeting expected future additional demand. In NZ50, electrification is deeper in sectors and a considerable amount of onshore wind emerges after 2030, reaching 18 TWh in 2050 (of a total electricity production of 64 TWh) and 24 TWh in 2060.

Given this generation, the use of storage is very limited and no nuclear production is used. A small quantity of CCS-equipped natural gas-fired production also appears in NZ50 in 2050 (400 MW).

4. How does biomass production and use evolve?

The rapid and substantial increase in biomass feedstock production in net-zero scenarios comes from agricultural residues (70 PJ in 2030 and the rest of the horizon compared with none today), while the remainder derives from a smaller quantity of additional wood biomass production (12 PJ more than in REF).

All agricultural residues serve to produce syngas and biochar in 2030, 2040 and 2050 (Figure 5.4f), resulting in negative GHG emissions. After 2050, around half of the total is diverted to BECCS hydrogen production and some BECCS electricity generation, meeting the negative emissions objective while supplying part of the higher demand for hydrogen and electricity. All the additional wood biomass in NZ50 goes to syngas and biochar production.

Figure 5.4e – Final energy consumption by sector – Manitoba

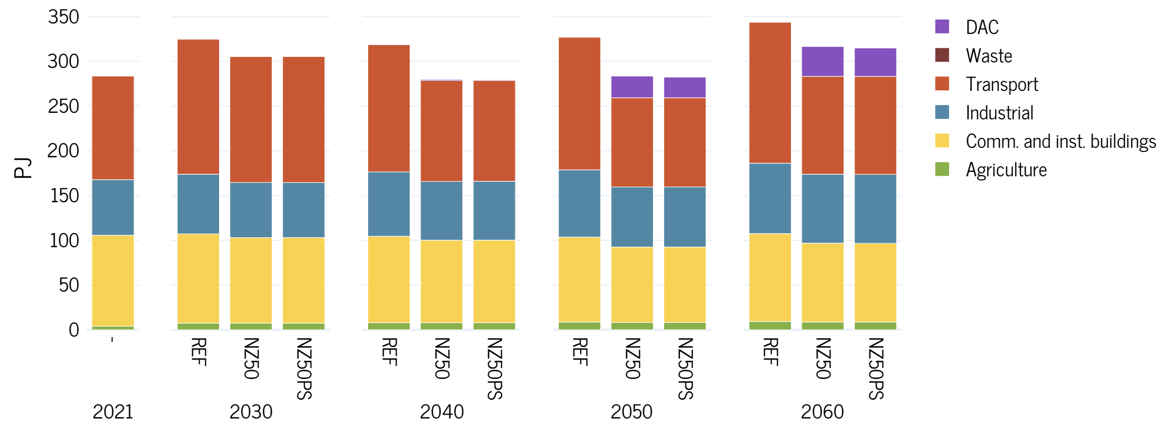
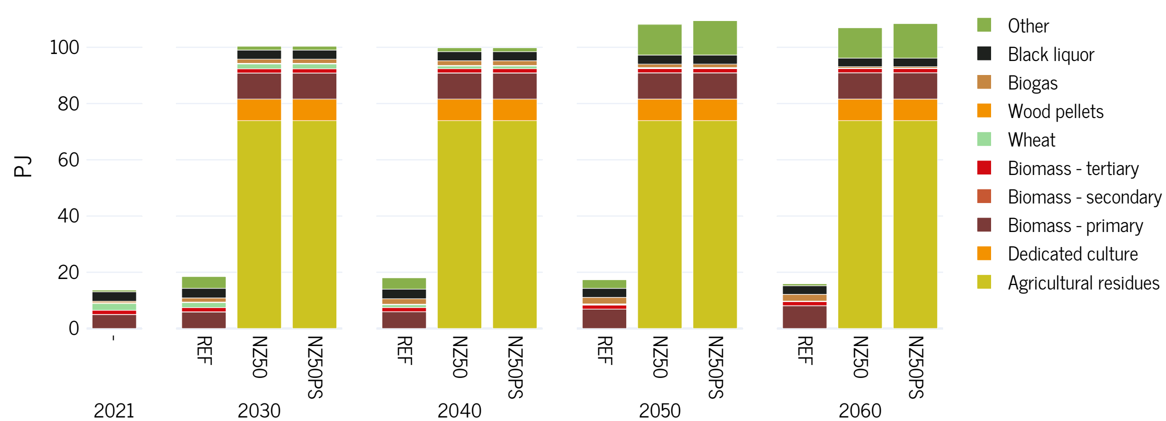


Figure 5.4f – Biomass feedstock used by type – Manitoba



5. How do the emissions trajectories compare to the national average?

In NZ50, Manitoba is at net-zero provincially in 2050 and 2060 (Figure 5.4a), while emissions grow 13% from current levels in REF. Direct air capture provides almost 2 $MtCO_2e$ in negative emissions in 2060, with biochar being the other main source of negative emissions until 2050 (between 3 and 4 $MtCO_2e$). After that, BECCS hydrogen and electricity production combine for more.

As is the case in Saskatchewan, agriculture emissions are by far the largest source of emissions remaining in 2050. In REF these amount to 9 $MtCO_2e$, roughly twice today's levels. Reductions are achieved in NZ50, although levels are still 50% higher than today (6 $MtCO_2e$). The rest of remaining emissions are in transport (1 $MtCO_2e$).

Bottom line: how does Manitoba stand out from other provinces in the results?

Based on the above results, a few key differences between Manitoba and the national average emerge:

- Manitoba reaches net-zero at the provincial level with an important contribution from BECCS and biochar in negative emissions.
- The emissions trajectory in net-zero scenarios presents a sharp departure from the reference scenario, where emissions rise to 2050, partly because of the rapid growth of off-road and freight transport.
- Electrification of industry is more significant than at the federal level but, similarly to the national scene, natural gas use in industry differs sharply between REF and NZ50.
- Although untapped hydroelectric potential enables the province to expand electricity production without SMRs, net-zero scenarios still require a considerable amount of wind generation.

5.5 Ontario

1. What are the main similarities and differences in energy consumption patterns across sectors?

In REF, total energy consumption (outside of energy production) in Ontario decreases over time (Figure 5.5e), from 2,650 PJ today to 2,330 PJ in 2050, in contrast to most of the rest of the country. This decrease is a result of energy technology changes in buildings and industry. The significant reductions observed in NZ50 reflect substantial decreases (-7% by 2030 and -24% by 2050, to 1,950 PJ with respect to today), compared to the more modest changes nationally (+1% by 2030 and 0% by 2050).

Both the starting point and the evolution of the energy mix in buildings closely matches the national results. Natural gas currently supplies 61% of the province's building needs, with almost all the rest supplied by electricity. Over time, this split is reversed in REF, while NZ50 almost fully decarbonizes. By 2050, the mix in NZ50 is comprised of electricity (76%), natural gas (6%), thermal solar (7%), as well as district heating (4%) and cooling (4%). The latter two are also present in REF.

Similarly to total energy consumption, increases in industrial energy consumption in REF are more modest in Ontario than at the national level. This is largely due to the province's ongoing electrification of steel production, which results in 42% less consumption (from 178 to 103 PJ) in the subsector by 2030. Over this short period, NZ50 sees more aggressive reductions of 66% at 61 PJ. The main transformations are short term as there are few additional reductions after 2030. This helps compensate part of the increase in energy consumption for other manufacturing, which is significant in both REF (+54% by 2050) and NZ50 (+37%).

In the transport sector, the decarbonization of freight transport is achieved with electricity and hydrogen. Although the latter's penetration is less substantial than in Quebec, it nevertheless becomes the most used source for heavy trucks as well (68% of consumption in 2050 in NZ50 with the rest coming from electricity) and also supplies two-thirds of the energy for rail. All small vehicles and medium trucks are shifted to electricity.

Figure 5.5a – Total GHG emissions by sector – Ontario

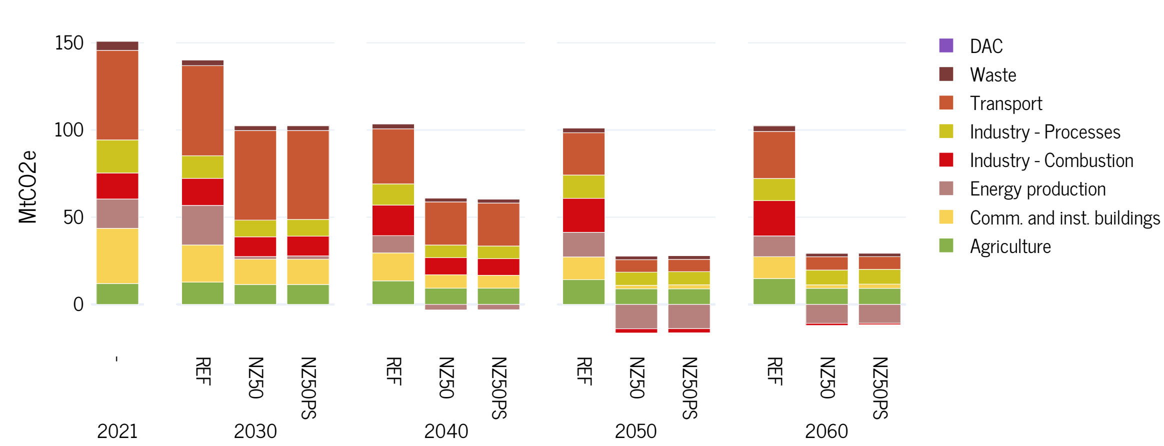
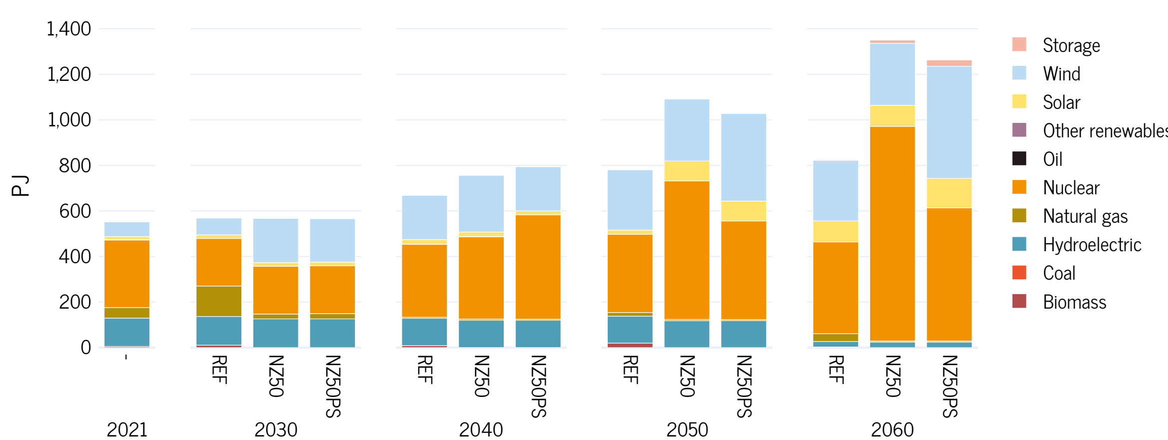


Figure 5.5b – Electricity generation by source – Ontario



The effect of the transformations to the energy mix on the total amount of energy needed for freight transport is significant. Due to efficiency gains, the shift away from natural gas and diesel in medium and heavy trucks results a reduction of more than half of the energy demand in road freight transport (100 PJ in 2050 for NZ50 vs. 210 PJ for REF in 2050). This is mainly because electricity use is much more substantial in NZ50 as it is significantly more efficient than hydrogen. This is even more visible in the results for 2060: hydrogen use increases further to 40% of the total in REF, replacing diesel and some natural gas, which does not change the total of 210 PJ. In NZ50, more electricity and less hydrogen are used in 2060.

2. How does primary and secondary energy production evolve in the province?

In all scenarios, natural gas production grows by 44% by 2040, from 120 to 170 PJ (Figure 5.5c). After that, this production further increases to 180 PJ in REF but is completely eliminated in NZ50. Biomass feedstock production doubles before 2030 in NZ50, from 200 to 410 PJ, while the increase to 320 PJ over the same period in REF is less, at 65% of current levels. Similarly to the national average, these levels then remain for the rest of the period.

Like in Quebec and New Brunswick, oil refining continues in all scenarios (Figure 5.5d), although levels are more than 20% lower in NZ50 than in REF for 2040 and 2050. Hydrogen production grows substantially over the period but particularly in net-zero scenarios: this increase accelerates sharply after 2040, reaching 190 PJ in NZ50 and 70 PJ in REF. However, at between 3 and 9%, it remains a small fraction of total energy use.

3. What is the extent of electrification and how does the electricity generation mix compare with the national average?

Similarly to the national trend, electricity production doubles in Ontario from now to 2050 in NZ50, rising from 150 to 300 TWh (550 to 1,100 PJ) prior to growing a further 24% before 2060 in net-zero scenarios (Figure 5.5b). Although the increase is less important in REF, generation still increases by 43% by 2050, climbing to 220 TWh.

Figure 5.5c – Primary energy production – Ontario

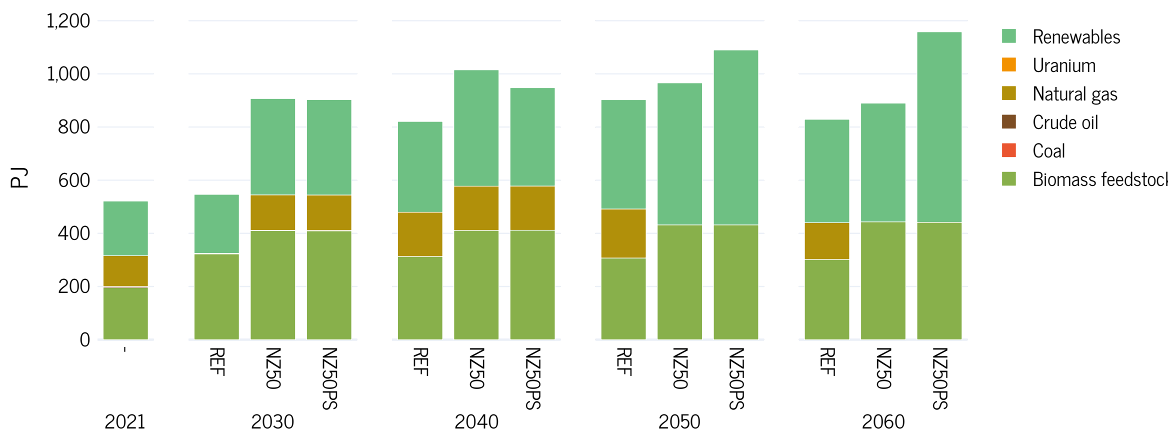
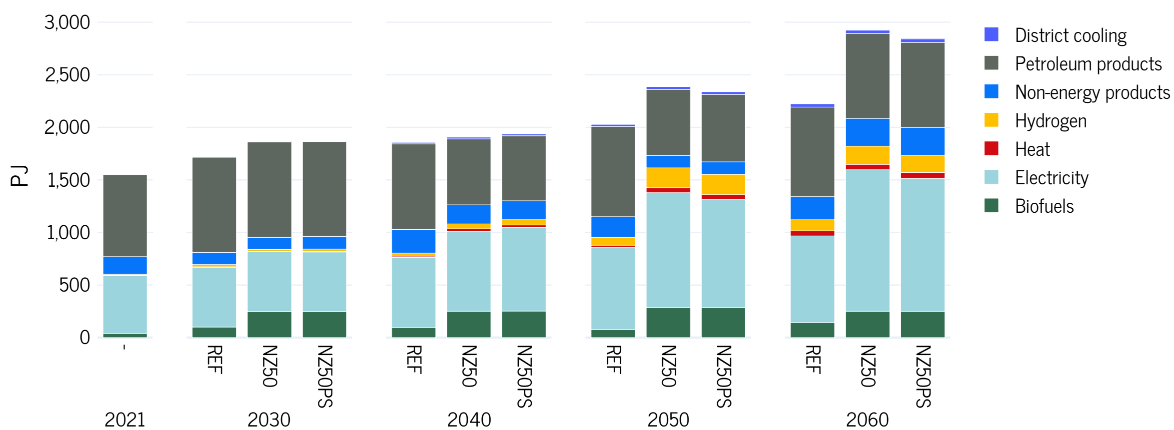


Figure 5.5d – Secondary energy production – Ontario



While the role of natural gas turbines grows on the short term, tripling its production before 2030 in REF (from 13 to 37 TWh), the coming into effect of the Clean Electricity Regulations in 2035 all but eliminates this production by 2040. No CCS-equipped facilities emerge in REF, while a very small quantity appears in NZ50 (2 TWh from 2030 through 2050).

In all scenarios, onshore wind substantially increases, although the buildup is slower in REF. Production levels converge in 2050 for REF and NZ50 to 75 TWh. In NZ50, an additional 20 TWh comes from centralized solar generation. Hydroelectric power plants remain at similar levels throughout 2050 in all scenarios, before decreasing more than 80% between 2050 and 2060 as many large dams reach their planned end-of-life. In practice, these facilities are likely to be refurbished to extend their life. In April 2024, the Government of Ontario indeed announced refurbishment plans for two of its fleet's largest facilities.

Nuclear energy continues to supply a large share of the mix. Conventional nuclear is maintained at levels similar to today's in 2040 and 2050, after a drop in 2030 due to the closing of the Pickering site.[1] SMRs grow slowly over time in REF to 18 TWh in 2050, while in NZ50, SMRs come to supply 30% of total production in 2050 (91 TWh). A much more substantial contribution of SMRs appears by 2060 for all scenarios following the closure of most conventional production sites at that point. Given the different hypotheses for SMR deployment in the alternative net-zero scenario, wind increases to almost double the amount in NZ50, with centralized solar showing higher levels as well. More storage becomes necessary in these scenarios.

This significant increase in electricity production in Ontario occurs through the transformation of large parts of today's generation mix, with natural gas turbines all but disappearing over the next 15 years. Notwithstanding the important longer-term uncertainty for the years between 2050 and 2060, the possibility of retiring of most conventional nuclear generation and hydroelectric production also indicates important choices further ahead, especially if SMRs encounter deployment difficulties.

Figure 5.5e – Final energy consumption by sector – Ontario

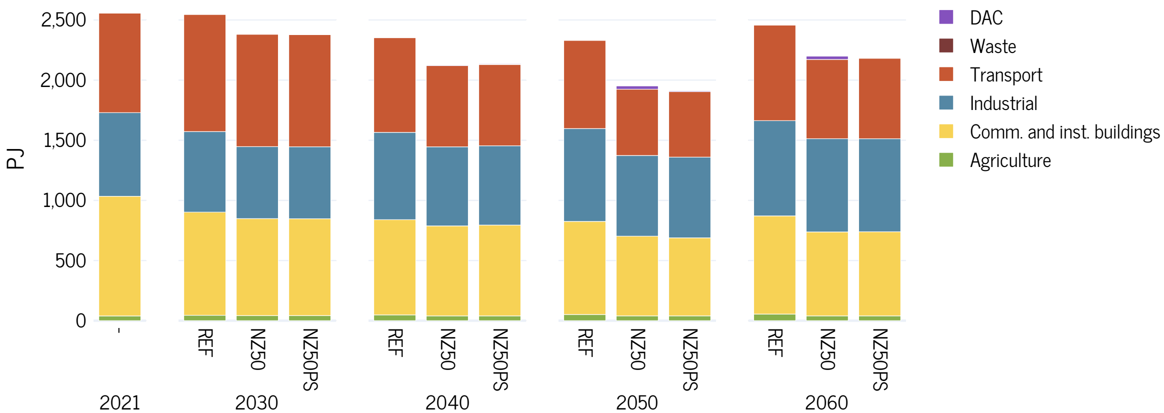
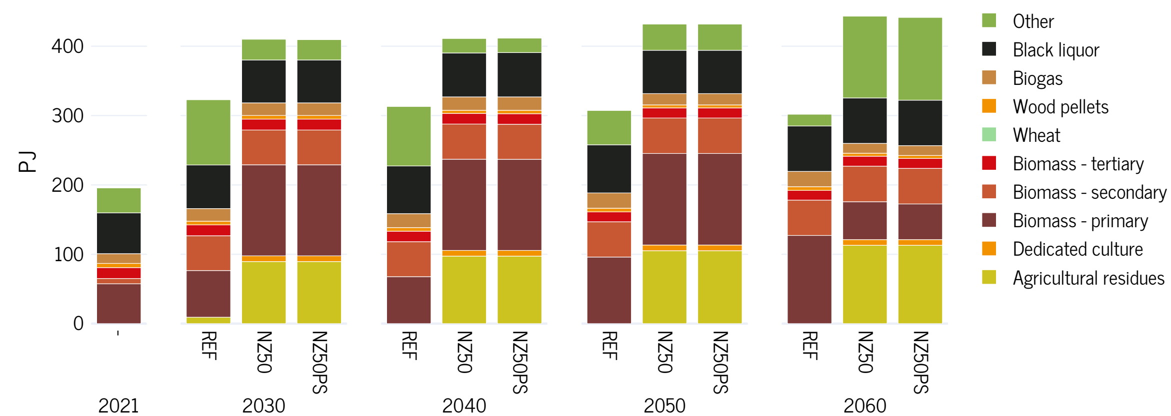


Figure 5.5f – Biomass feedstock used by type – Ontario



[1] At the end of January 2024, the Ontario government announced that the Pickering site will be partially refurbished; this refurbishment is not included in the modelling presented here. Its effect will likely be to reduce the share of small modular reactors in Ontario's electricity production over the coming decades.

4. How does biomass production and use evolve?

In REF, the increase in biomass feedstock production comes mainly from wood biomass; in NZ50 agricultural residues also appear as an important share (100 PJ from nothing today) of the total (400 PJ). In a pattern similar to that observed in other provinces, almost all agricultural residues are used for biochar and syngas production in 2030 and, starting in the 2040s, a share of this is taken by BECCS hydrogen production (Figure 5.5f).

Biochar production is also the main use of the wood biomass. After 2040, biomass used in heat boilers (in the manufacturing and pulp and paper industries) is diverted toward more biochar production, along with BECCS hydrogen production. The use over time of both agricultural residues and wood biomass therefore helps provide negative emissions in addition to the energy produced (syngas and hydrogen).

5. How do the GHG emissions trajectories compare to the national average?

In REF, emissions are reduced 31% by 2040, to 103 from today's 151 $MtCO_2e$, and then remain at similar levels until 2060 (Figure 5.5a). The province's industrial profile makes it more expensive to reach net-zero and 11 to 18 $MtCO_2e$ of net emissions remain in 2050 and 2060 in net-zero scenarios. While the use of BECCS and biochar make industry's combustion emissions and those from energy production negative, agriculture, industrial processes and transportation emissions combine to constitute a larger total.

By 2050, agriculture emissions decline by 25% in NZ50, from 12 to 9 $MtCO_2e$, while growing slightly in REF. Industrial process emissions are cut by more than half by 2050 in NZ50, from 19 to 8 $MtCO_2e$, slightly more than the national average (-50% by 2050 in NZ50). While transport emissions decrease by 86% before 2050, from 52 $MtCO_2e$, the province's large size results in a remaining 7 $MtCO_2e$.

No direct air capture is used as the national cost optimization leads to building operations elsewhere, which also plays a role in keeping the net emissions positive.

Bottom line: how does Ontario stand out from other provinces in the results?

Based on the above results, a few key differences between Ontario and the national average emerge:

- Contrary to the national numbers, final energy consumption does not grow on the short term in REF.
- Even in REF, the CER triggers major transformations in the electricity sector as natural gas is not used to meet the substantial increase in demand after 2030.
- ùIn NZ50, the electricity mix uses a very large quantity of SMRs, starting mainly in 2050, with a strong contribution from wind as well.
- Biomass use doubles in NZ50 and is also diverted away from current consumption points to biochar and syngas production, as well as BECCS hydrogen production.
- Emissions remain positive in the province, despite biochar and BECCS in industry and energy production.

5.6 Quebec

1. What are the main similarities and differences in energy consumption patterns across sectors?

Compared with the national numbers, energy consumption in industry occupies a much larger share of total consumption in Quebec, amounting to 38% (660 PJ) of the total today (compared with 28% nationwide). This share increases over time, reaching around 45% of the total in both REF and NZ50 in 2050 since transportation energy consumption declines due to electrification (Figure 5.6e). Otherwise, the evolution of final energy consumption sees REF totals increase slightly before 2030, from 1,740 to 1,840 PJ, and then again to 1,940 PJ from 2050 to 2060. NZ50 maintains lower levels than REF throughout but experiences an important increase after 2050, from 1690 to 1900. As is the case at the national level (see Chapter 2), this shows that the cost-effective transformations to reach net-zero have some limits and that after 2050, population growth makes increased energy demand impossible to avoid.

In contrast to the national average, buildings are already largely decarbonized in Quebec, with electricity supplying 71% of total consumption. In both REF and NZ50, other sources like natural gas and heating oil gradually diminish in importance over time and electricity grows to 83% of the total in 2050 in REF. In NZ50, electrification is more significant, replacing all natural gas, heating oil, other fossil fuels, and wood biomass. Thermal solar, geothermal and district heating also play a small role from 2040 onward in NZ50.

With industry consumption growing over time even in NZ50 (+15% by 2050 vs. +23% in REF), transformations in the energy mix for the sector are important to understand the net-zero trajectory. The main contrasts between REF and NZ50 are not only the more extensive electrification in the latter scenario, but also the use of hydrogen for 17% of the needs in 2050 in NZ50, while hydrogen is not used at all in the sector in REF. These transformations combine to reduce natural gas consumption by 83% before 2050 (to 20 PJ), rendering it marginal in the mix. In contrast, it grows to 24% of the total industrial demand in 2050 (200 PJ) in REF.

Figure 5.6a – Total GHG emissions by sector – Quebec

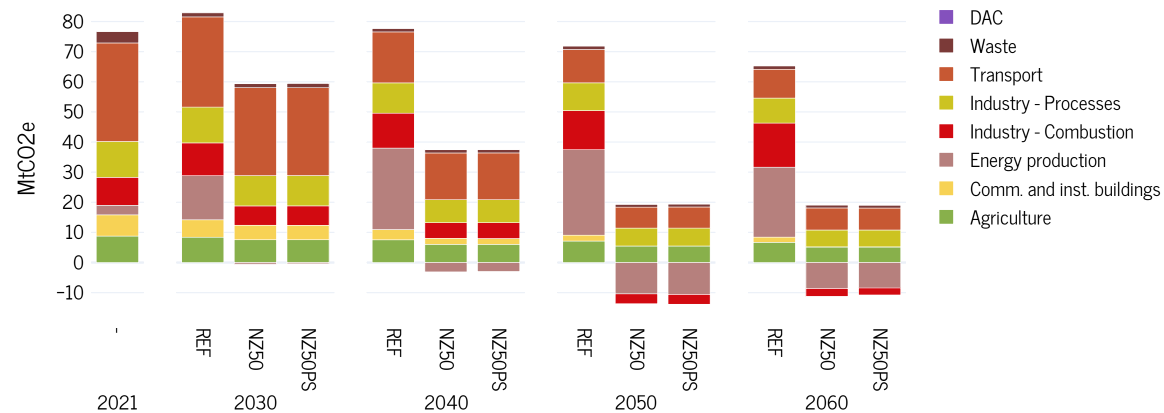
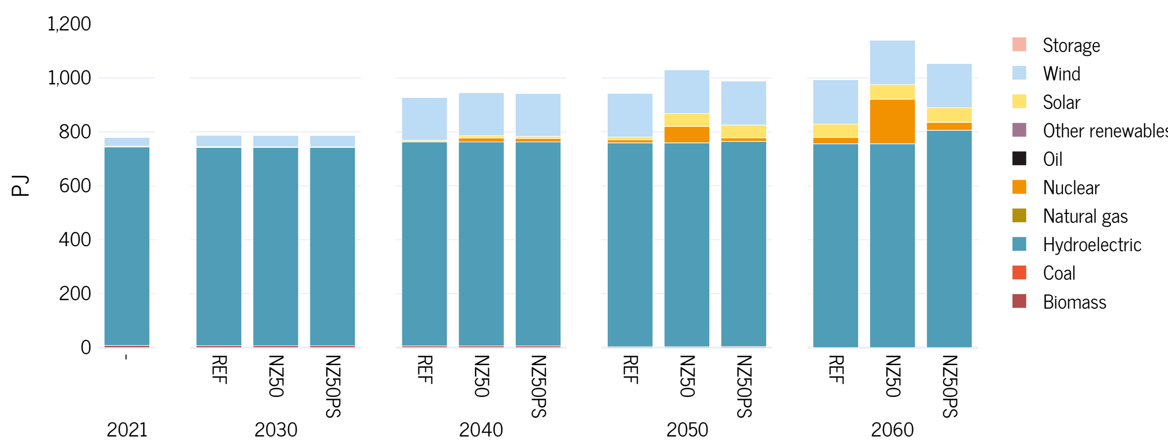


Figure 5.6b – Electricity generation by source – Quebec



Consumption for transport in Quebec evolves similarly to the national average, although oil products retain a larger share of the total in 2050 (21% vs. 14% for Canada). Decarbonization of freight transport is achieved with electricity and hydrogen: the latter is the most commonly used source for heavy trucks (74% of consumption in 2050 in NZ50 with the rest coming from electricity) and also supplies two-thirds of the energy for rail. All small vehicles and medium trucks are shifted to electricity.

The difference in freight transport between NZ50 and REF is important: in REF, while hydrogen plays a large role for heavy trucks as in NZ50, electricity's role is less extensive, leading to a higher total consumption. Moreover, medium trucks do not shift to electricity in REF: as a result, consumption of oil products in the sector remains important in this scenario despite the electrification of small passenger and freight transport vehicles.

2. How does primary and secondary energy production evolve in the province?

Since no fossil fuel extraction takes place in Quebec, primary energy production is only for biomass feedstock and primary electricity (Figure 5.6c), dominated by hydroelectric production. In both REF and NZ50, biomass feedstock production increases by 37% by 2030, after which levels remain constant for REF, as is the case in several other provinces. What is different in Quebec is that this production continues to increase over time in net-zero scenarios, with a total increase of 61% by 2050 from current levels. A closer look reveals that the increase to 2030 is chiefly due to more wood biomass, while a larger quantity of agricultural residues are produced from 2030 to 2040.

In secondary energy production (Figure 5.6d), oil refining continues and even grows 30% over time in both REF and NZ50. Hydrogen production increases to 160 PJ (from 10 PJ today) in NZ50, all after 2040, although this production is much more significant in REF, where levels grow to 160 PJ in 2030, before more than doubling to 350 PJ in 2040. However all this production is destined for export in REF, whereas in NZ50, hydrogen is not exported and serves to meet domestic demand.

Following the national trend, in REF, hydrogen is produced by means of different technologies than in NZ50. In the latter, production is largely decarbonized, using CCS-equipped autothermal reforming and BECCS. In REF, in the absence of the emissions constraint, steam methane reforming from natural gas imported from other provinces is used for the entire production.

Figure 5.6c – Primary energy production – Quebec

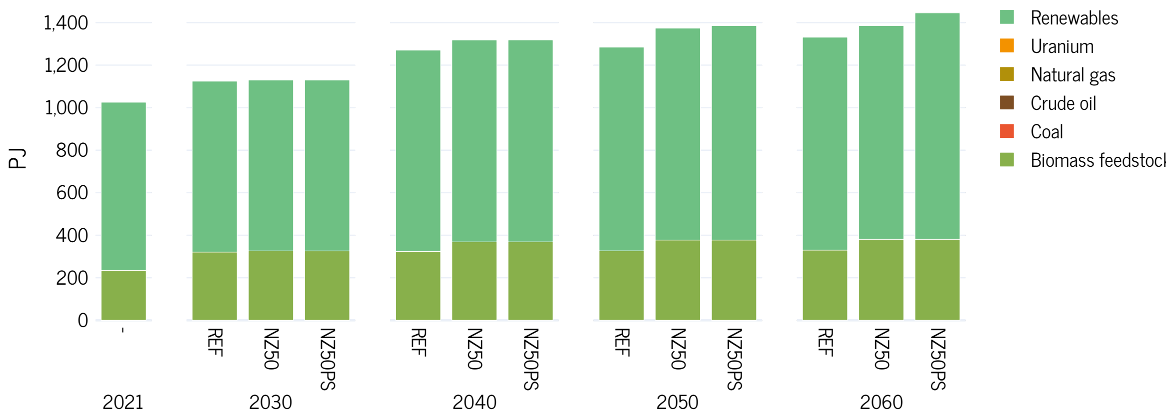
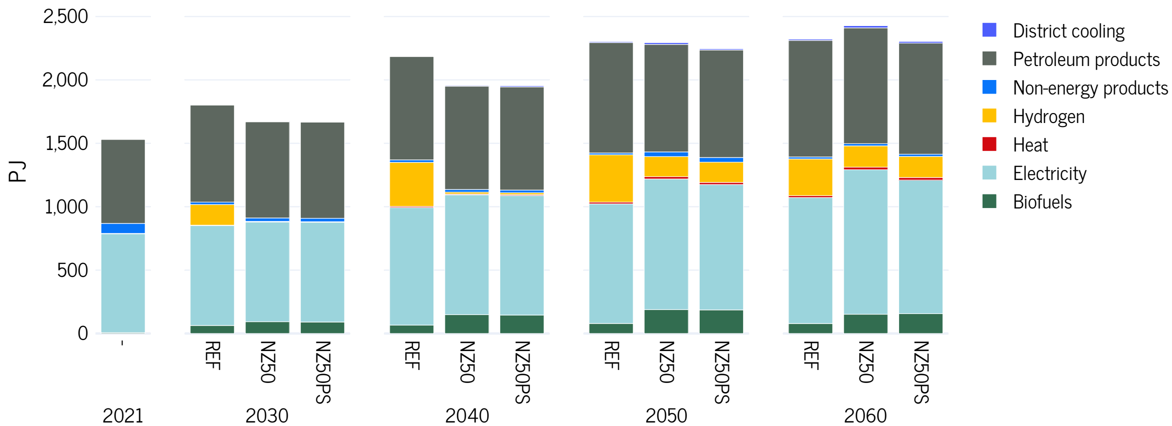


Figure 5.6d – Secondary energy production – Quebec



3. What is the extent of electrification and how does the electricity generation mix compare with the national average?

On the 2050 horizon, electricity generation in net-zero scenarios increases by a smaller margin in Quebec (32%) than the doubling at the national level (Figure 5.6b). This is partly a reflection of Quebec's more advanced electrification of services, although this result may be a significant understatement of the needs to reach net-zero within the province. Given that the optimization occurs at the national level, Quebec is one of the provinces where remaining emissions are the most significant as a net 6-8 $MtCO_2e$ remain in 2050 and 2060, even after accounting for -15 $MtCO_2e$ negative emissions from BECCS hydrogen production and biochar. Keeping these emissions sources reduces the need for the large quantities of electricity necessary for the last-mile decarbonization of some services, including some industrial processes and heavy transport.

Since no new hydroelectric production is planned, the increase comes mainly from wind (which increases to 45 TWh by 2040) before nuclear SMR production emerges to supply 17 TWh in 2050 and 50 TWh in 2060. This corresponds to an installed capacity of 2 GW and 6 GW respectively.

This particular result is extremely sensitive to the assumptions on SMR costs and the alternative NZ50PS scenario yields a much more limited contribution from SMRs to the generation mix, with 4 TWh and 8 TWh in 2050 and 2060. In 2060, the difference is partly compensated by additional hydroelectric production.

With more than 10 TWh, centralized solar also plays a role from 2050.

Figure 5.6e – Final energy consumption by sector – Quebec

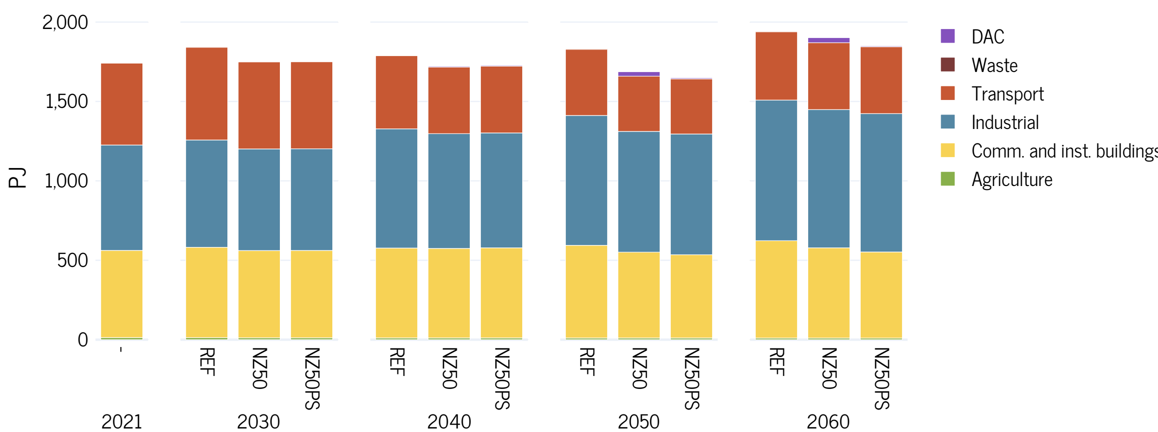
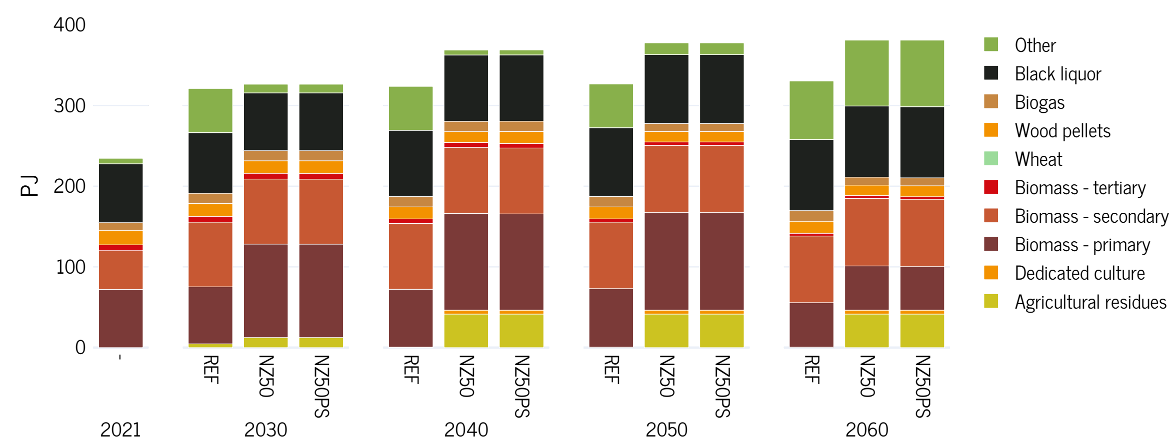


Figure 5.6f – Biomass feedstock used by type – Quebec



4. How does biomass production and use evolve?

The additional agricultural residues, only present in net-zero scenarios, are first directed to biochar and syngas production (in 2030 and 2040). Subsequently, a growing share of these residues is instead used for BECCS hydrogen production (Figure 5.6f). By 2060, this becomes the main destination for agricultural residues, with 75% going to gasification in hydrogen production.

The larger quantities of wood biomass are used in distinct patterns across scenarios. In REF, the distribution of wood biomass among different services remains largely unchanged over time. However, NZ50 involves significant changes. Heat boilers in the pulp and paper and manufacturing industries all but stop using biomass and by 2050 almost two-thirds of wood biomass is destined for biochar and syngas production, resulting in negative emissions. From 2050, NZ50 also shows some hydrogen production from this feedstock in BECCS processes.

5. How do the emissions trajectories compare to the national average?

Since the province's industrial profile makes it more expensive for it to reach net-zero, 6-8 $MtCO_2e$ of net emissions remain in 2050 and 2060 (Figure 5.6a). While the use of BECCS processes and biochar make industry's combustion emissions and those from energy production negative, agriculture, industrial processes and transportation emissions combine to a make larger total.

Nevertheless, agriculture emissions reductions are significant within the province, decreasing by 37% in NZ50, which is much more than the national average (-16%). Even in REF, these emissions decline 19%, compared with the 21% increase nationwide. Industrial process emissions are close to the national average in terms of reductions (-50% by 2050 in NZ50), reflecting the problems inherent in reducing process emissions further in a number of industrial sectors.

No direct air capture is used in Quebec as the national cost optimization leads to building operations elsewhere, which also plays a role in keeping its net emissions positive.

Bottom line: how does Quebec stand out from other provinces in the results?

Based on the above results, a few key differences between Quebec and the national average emerge:

- Industry accounts for a much larger share of total energy consumption in Quebec than it does in the national average and this share increases over time in all scenarios.
- Electricity and hydrogen penetration in road freight transport are very important in NZ50, in contrast to REF, which maintains a large quantity of diesel.
- Additional electricity needs are substantial in net-zero scenarios for the province, although this increase is more modest than at the national level; it is likely that this is an underestimation of the need as the make-up of the industrial sector is kept constant in the scenarios and does not reflect the importance of new demand drivers for the sector.
- Biomass becomes a key contributor to negative emissions, with biochar from 2030 and BECCS electricity and hydrogen production after 2050.
- Since no DAC is used in Quebec, the province's extensive agriculture and industrial activities leave some remaining emissions.

5.7 New Brunswick

1. What are the main similarities and differences in energy consumption patterns across sectors?

The overall consumption in economic sectors in New Brunswick evolves differently from the national average as REF levels do not increase before 2030, remaining at 170 PJ (Figure 5.7e). This is largely owing to the province's very small agriculture sector, as well as the modest increase in consumption for transport (+7% by 2030, compared to +19% at the national level). As a result, the difference over time between REF and NZ50 is minimal, with NZ50 levels eventually being only 7% lower than REF in 2050 and 2060 before taking into account the energy consumed by DAC operations. When including DAC, total consumption in NZ50 is higher than in REF, although lower than today's levels.

New Brunswick's current energy mix in buildings differs from other provinces in important ways. Electricity supplies close to two-thirds of the total today, with the rest provided by wood biomass, heating oil and natural gas, in decreasing order of importance. In REF, the phase-out of heating oil is complete and electricity takes a small share away from wood. In NZ50, all natural gas, heating oil and wood are eliminated by 2050, with more efficient electric technologies taking over 95% of the mix and a small quantity of district heating supplying almost all the rest.

In industry, net-zero scenarios decarbonize mainly after 2040, replacing some bioenergy and natural gas with electricity and hydrogen. Hydrogen in particular appears only in net-zero scenarios, supplying around 20% of demand from 2050.

Hydrogen penetration in transport in New Brunswick is more limited than the national average, largely as a result of a smaller share in heavy trucks in energy consumption for freight transport (13% vs. 39% nationwide). By 2050, road freight reduces consumption by half in both REF and NZ50; off-road consumption does not increase in absolute terms but grows in relative importance, with 36% of total consumption for the sector in 2050 in NZ50, compared with 18% today. The rest of road transport is almost completely electrified.

Figure 5.7a – Total GHG emissions by sector – New Brunswick

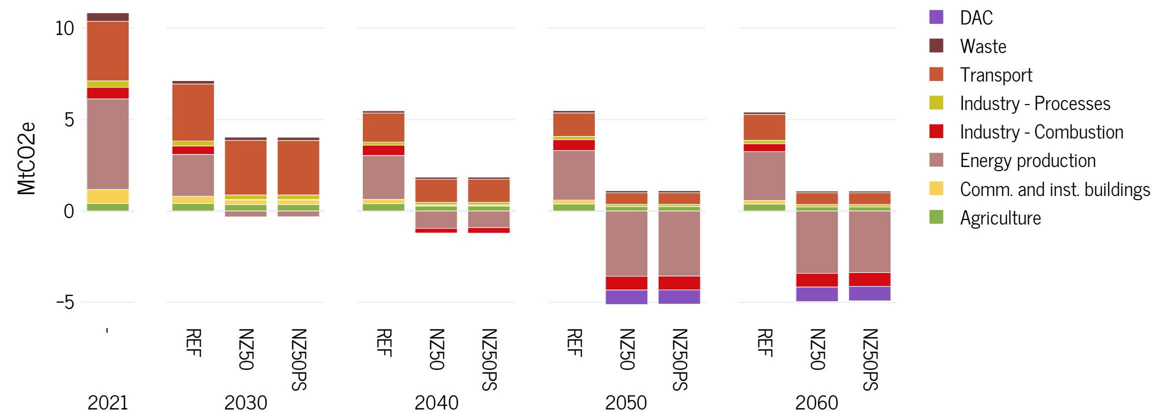
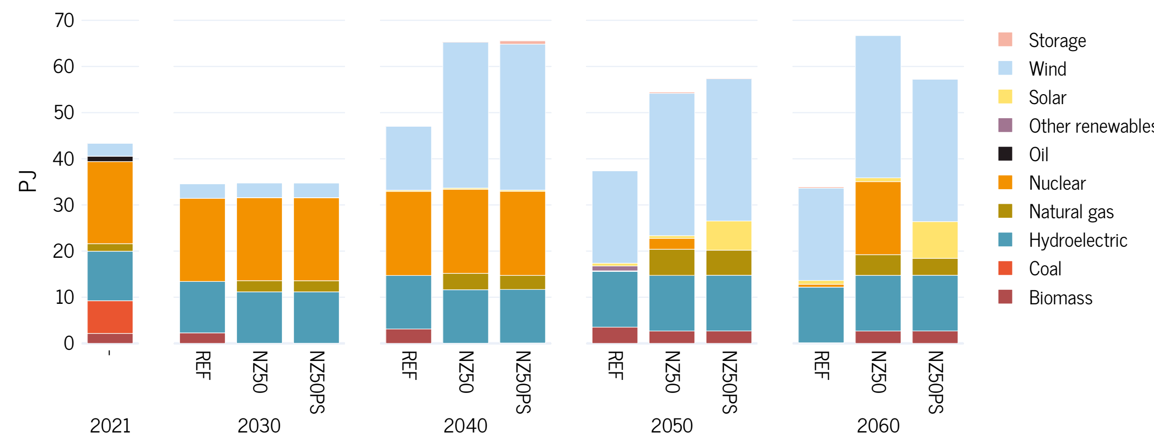


Figure 5.7b – Electricity generation by source – New Brunswick



2. How does primary and secondary energy production evolve in the province?

Although there is virtually no primary fossil fuel production in New Brunswick, the Irving Refinery brings significant transformation. Biomass feedstock production grows by 50% in NZ50 but not in REF, while renewable electricity production more than doubles to 30 PJ in 2050 in REF and to more than 40 PJ in NZ50 (Figure 5.7c).

Both REF and NZ50 result in the refinery producing a larger quantity of oil products over time (Figure 5.7d) as it is maintained to supply local demand as well as exports. In other secondary energy production, a relatively small quantity of hydrogen is produced (20 PJ), although only in net-zero scenarios.

3. What is the extent of electrification and how does the electricity generation mix compare with the national average?

Additional electricity production is much more limited in New Brunswick than in other provinces and than the national average (Figure 5.7b). In REF, production in the province even declines by 14%, while in NZ50 the increase is only 26% before 2050, compared with its doubling nationwide. However, the province's rising electricity consumption is met mainly by larger interprovincial transfers from Newfoundland and Labrador (around 14 TWh from 2030 to 2050).

Before 2050, additional onshore wind production (9 TWh) is the only important change. Furthermore, once the Point Lepreau nuclear power plant is retired in the 2040s, SMRs contribute an almost equivalent quantity (4 TWh) in 2060. Given the increase in wind, some storage emerges from 2040 (400 MW).

4. How do biomass production and use evolve?

All the increase in biomass production comes from wood biomass; very little agricultural residue is used in the province. Wood biomass sees a doubling of primary and secondary forms. In 2030 and 2040, all of this feedstock goes toward the production of syngas and biochar (Figure 5.7f), resulting in negative emissions. As of 2050, as is the case in other provinces, part of the feedstock is used for BECCS electricity and hydrogen production.

Figure 5.7c – Primary energy production – New Brunswick

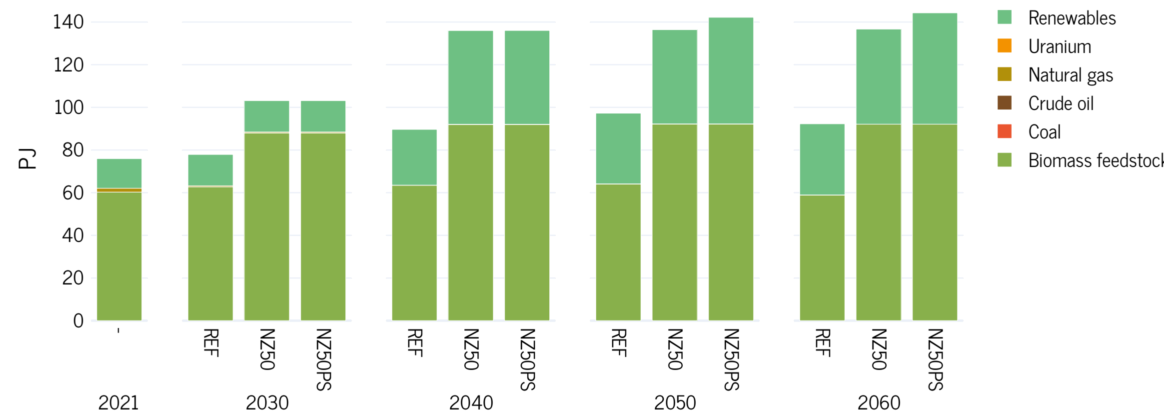
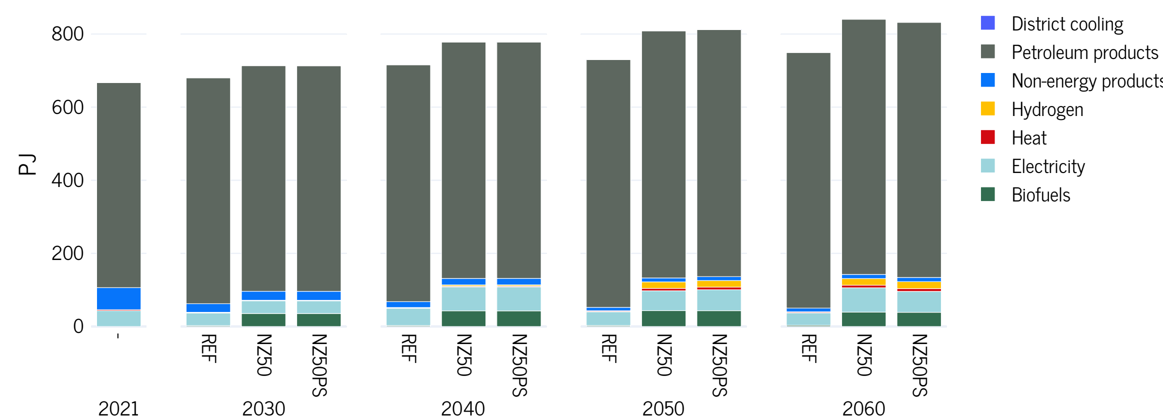


Figure 5.7d – Secondary energy production – New Brunswick



5. How do the emissions trajectories compare to the national average?

Starting at 11 $MtCO_2e$, New Brunswick produces only a very small quantity of the emissions remaining in 2050 (Figure 5.7a), owing to the province's limited industrial and agricultural sectors. As a result, transport is the main sector showing positive emissions in 2050 (1 $MtCO_2e$).

The combination of biochar, BECCS electricity and hydrogen production, together with transformations in the pulp and paper industry, lead to considerable negative emissions given the size of the province, making it clearly net negative in 2050 (-4 $MtCO_2e$).

Bottom line: how does New Brunswick stand out from other provinces in the results?

Based on the above results, a few key differences between New Brunswick and the national average emerge:

- Energy consumption increases less on the short term than the national average given the province's small agricultural sector and a more limited increase in transport.
- Electricity needs also show a smaller increase over time in both REF and net-zero scenarios.
- While electrification is substantial in the transport sector, the importance of off-road grows over time, resulting in a transport sector that is less decarbonized than the national average.
- The province has net negative emissions in 2050, in part due to fewer activities from industry and agriculture compared to the national average.

Figure 5.7e – Final energy consumption by sector – New Brunswick

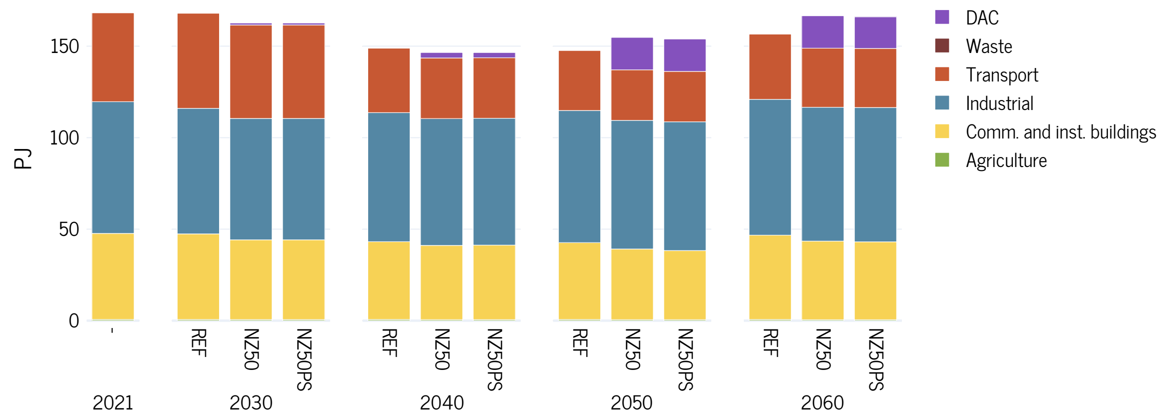
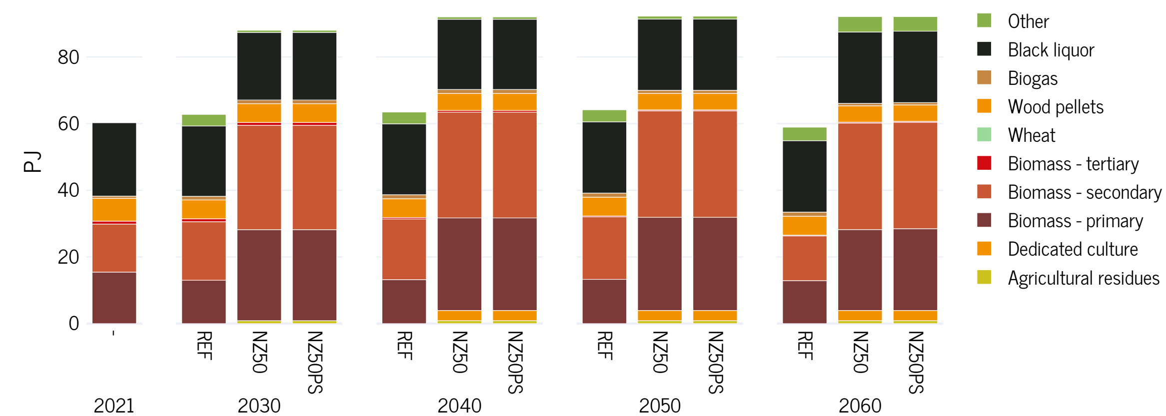


Figure 5.7f – Biomass feedstock used by type – New Brunswick



5.8 Nova Scotia

1. What are the main similarities and differences in energy consumption patterns across sectors?

On the short term, final energy consumption in Nova Scotia (Figure 5.8e) resembles the national pattern, with REF consumption increasing 9% by 2030, from 157 to 162 PJ, before dropping 15% to 146 PJ by 2040, resulting from the increased efficiency associated with the electrification of some services. After 2030, NZ50 decreases more quickly than REF, ending at levels 22% lower than today in 2050, at 120 PJ. However, when DAC energy consumption is included, total consumption is the same in NZ50 and REF in 2050 and even grows more quickly in NZ50 before 2060.

Energy consumption in buildings diminishes 22% by 2050 in NZ50, a decrease similar to that of the national average. However, the transformations required to achieve this reduction are different than nationwide, given the 23% share of fuel oil and the 18% share of wood in the province today. Electrification, which is important even in REF, reaches 80% of the supply in 2050. Wood retains a 18% share in REF in 2050, while it disappears in NZ50, where it is replaced by a combination of more electricity, syngas, district heating and thermal solar.

Consumption in industry increases by 20% before 2050, from 23 to 28 PJ; there is little difference between REF and NZ50 for these levels. However, the mix evolves very differently across scenarios: in NZ50, with hydrogen plays an important role starting in 2050 (22% of the total), whereas it plays no role at all in REF. This replaces natural gas and some bioenergy, while electricity use is similar in REF and NZ50 (35% of the total in 2050).

In NZ50, freight transport in the province is fully decarbonized due to the emergence of a mix of hydrogen and electricity in heavy trucks, while passenger transport is fully decarbonized even in REF. Rail is electrified first and additional demand for freight transport by rail after 2050 is supplied by hydrogen.

Figure 5.8a – Total GHG emissions by sector – Nova Scotia

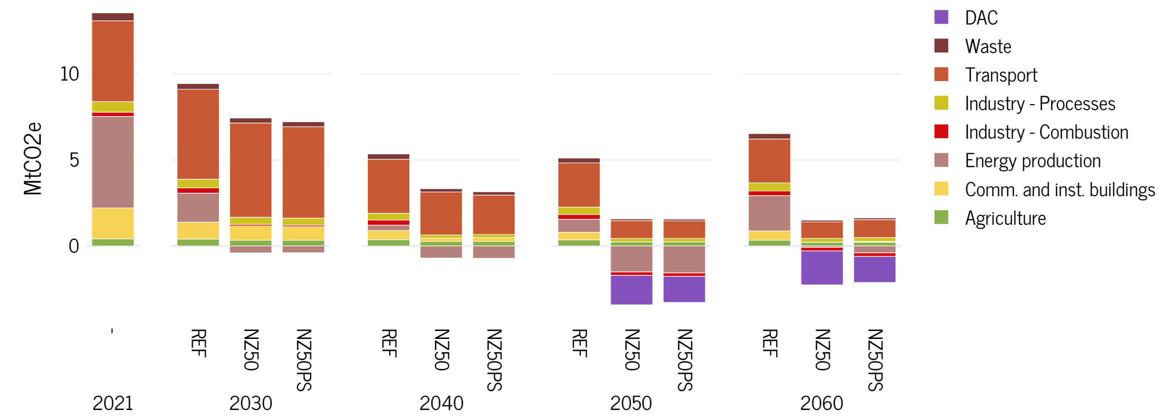
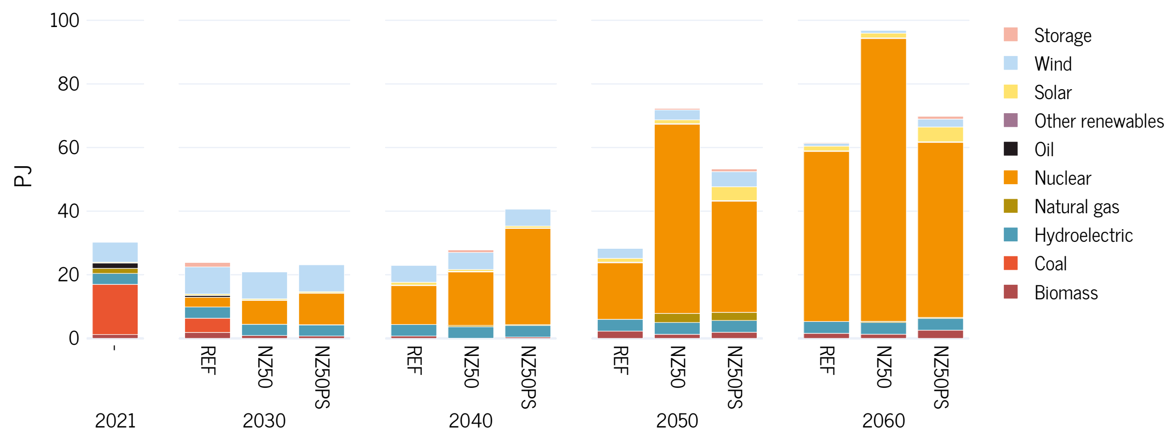


Figure 5.8b – Electricity generation by source – Nova Scotia



2. How does primary and secondary energy production evolve in the province?

While Nova Scotia's primary energy production is small, the province does extract some coal and natural gas (4 PJ), although this is phased out over time in all scenarios (Figure 5.8c). The main production is biomass feedstock (30 PJ today), which increases by around 50% in both REF and NZ50. Renewable electricity production is limited in the province (3 TWh today) and this quantity remains similar over time even in NZ50.

Most electricity is produced from secondary sources, even across time in the net-zero scenario. Similar to the situation in other provinces, hydrogen production emerges in the late 2040s (Figure 5.8d), albeit in rather small quantities (peaking at 20 PJ in 2060 for NZ50).

3. What is the extent of electrification and how does the electricity generation mix compare with the national average?

Apart from Saskatchewan, Nova Scotia is the only province where coal currently produces the largest share of total electricity generation, at around 50% (4 TWh) of the total in 2021. Due to regulation, this production is almost inexistent by 2030 and the phase-out is completed shortly thereafter (Figure 5.8b).

REF also shows an outlier pattern for the province, similar to New Brunswick: total electricity generated declines in 2030 and 2040, then returns to current levels in 2050 before more than doubling until 2060. Like New Brunswick's, the province's electricity consumption nonetheless increases through larger interprovincial transfers from Quebec and Newfoundland, adding 3 TWh to today's total every decade in REF.

NZ50 shows a similar pattern on the short term, with levels 30% lower in 2030. The increase in generation after 2030 occurs earlier than in REF and is more substantial. Between 2040 and 2050, generation increases by 160%, reaching 20 TWh, and continues to grow to 27 TWh in 2060. What distinguishes Nova Scotia further from other provinces is that onshore wind shows only a slight increase (and even decreases by half by 2050) and the overwhelming share of the change over time comes from nuclear SMRs. Therefore, the fact that production increases sharply later than 2050 and less substantially in REF is directly associated with an earlier and larger rise of SMRs in NZ50. A small quantity of SMRs is also assumed to be already in service in 2030 (from 100 MW in REF to 260-340 MW in net-zero scenarios).

Figure 5.8c – Primary energy production – Nova Scotia

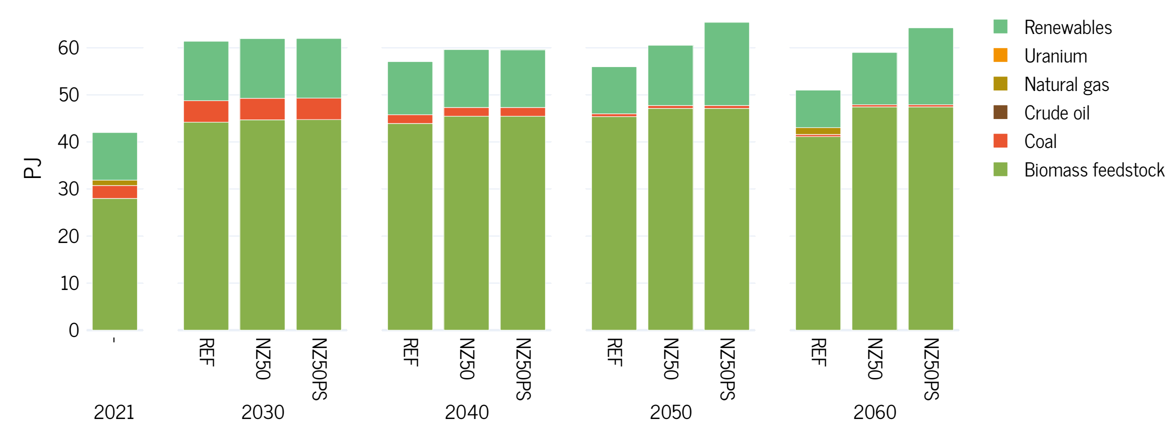
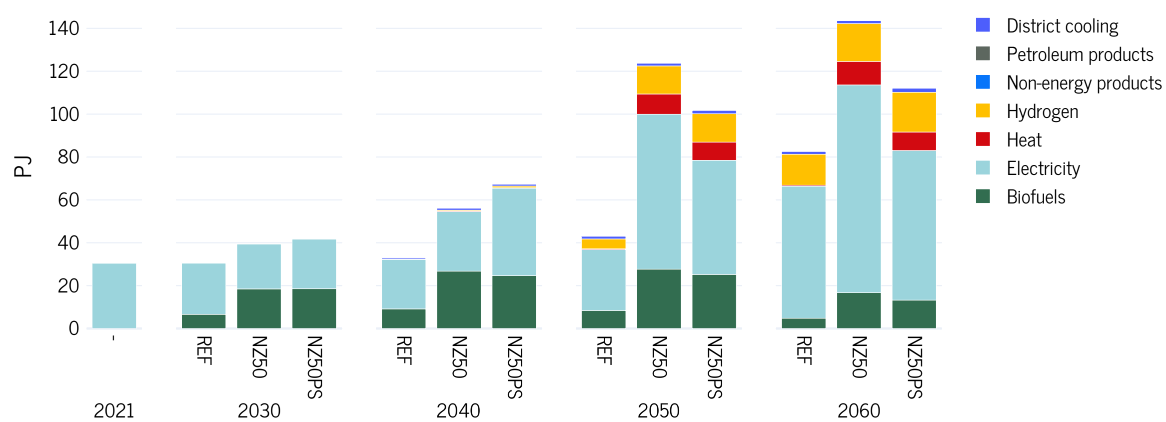


Figure 5.8d – Secondary energy production – Nova Scotia



It is important to note that this does not mean a delay in the electrification of services in Nova Scotia compared with other provinces. Instead, the 2030 to 2050 period sees more electricity imports from neighbouring provinces and once SMRs are deployed the need for these imports vanishes. The role of offshore wind may also be underplayed in the results as current cost projections make it a more expensive option despite the considerable resources available.

4. How does biomass production and use evolve?

The increase in biomass feedstock production in net-zero scenarios comes overwhelmingly from wood biomass. In NZ50, this is used to produce syngas and biochar (Figure 5.8f), resulting in negative emissions. In contrast, more wood biomass remains over time for space heating in buildings in REF.

All agricultural residues serve to produce syngas and biochar in 2030, 2040 and 2050, resulting in negative GHG emissions. After 2050, around a third of the total is diverted to BECCS hydrogen production and some BECCS electricity generation, again meeting the negative emissions objective while supplying part of the higher demand for hydrogen and electricity. All the additional wood biomass in NZ50 goes to syngas and biochar production.

Figure 5.8e – Final energy consumption by sector – Nova Scotia

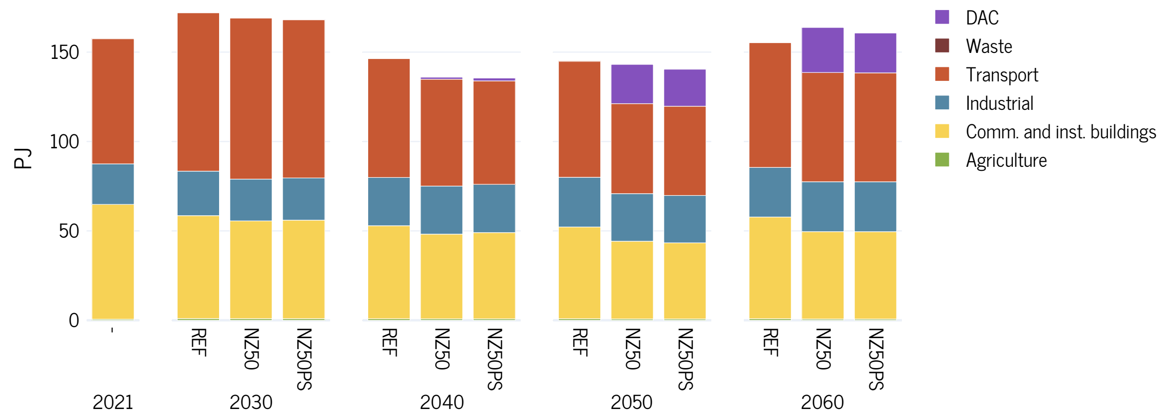
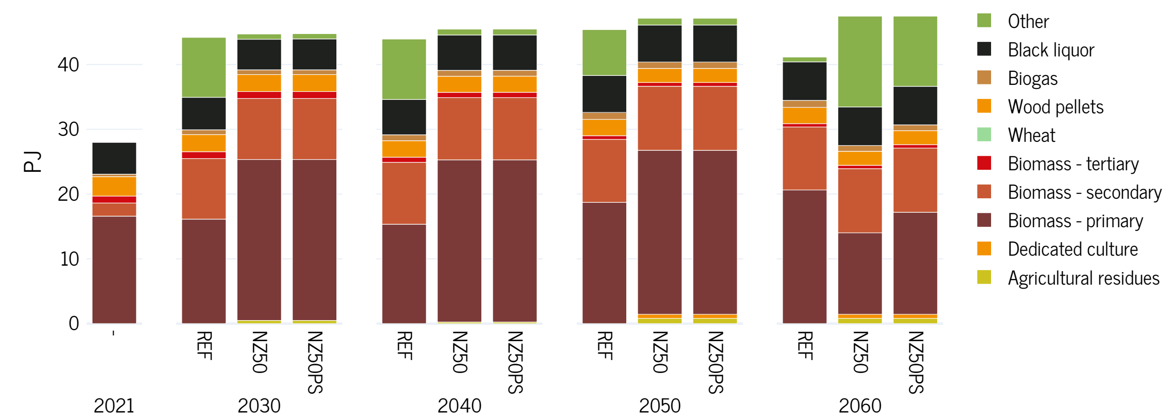


Figure 5.8f – Biomass feedstock used by type – Nova Scotia



5. How do the emissions trajectories compare to the national average?

Starting at around 13 $MtCO_2e$ today, Nova Scotia becomes net negative in 2050, with almost no remaining emissions from agriculture or industrial processes and only 1 $MtCO_2e$ remaining in transport (Figure 5.8a). With the industry and energy production sectors combining to -1 $MtCO_2e$ in negative emissions, and DAC capturing an additional 2 $MtCO_2e$ in 2050, the province's total amounts to -2 $MtCO_2e$.

Bottom line: how does Nova Scotia stand out from other provinces in the results?

Based on the above results, a few key differences between Nova Scotia and the national average emerge:

- Although energy consumption patterns in Nova Scotia evolve similarly to the national average, a more substantial transformation in buildings is required given the large share of natural gas today.
- Hydrogen contributes to the energy mix in industry only in the net-zero scenarios.
- Contrary to other provinces, Nova Scotia's electricity generation fleet waits for SMRs to be substantially deployed before expanding production, with little contribution from other sources, even wind. This is the case in REF as well as in NZ50, although the larger electricity needs in NZ50 lead to an earlier deployment of SMRs in the 2040s. An important caveat to this result is the potential role of offshore wind projects, which does not appear in the results largely because cost projections are more difficult to assess precisely at present.
- Aside from electricity, energy production from biomass increases in the province, mainly to meet needs for negative emissions applications.
- With these operations and a contribution from DAC, Nova Scotia is net negative by 2050, with very limited remaining emissions.

5.9 Prince Edward Island

1. What are the main similarities and differences in energy consumption patterns across sectors?

In the REF scenario, the province's total final energy consumption (28 PJ) ends up at levels similar to today in 2050, after which it increases by 10% to 2060 (Figure 5.9e). As is the case in most provinces, current measures lead to efficiency improvements through changes in the energy mix, which compensate for population growth and the consequent increase in demand until 2050. In NZ50, reductions in consumption are more significant, resulting in a total consumption decrease of 17% from today's levels (23 PJ) by 2050.

Currently, 24% of energy consumption in buildings comes from wood biomass, a share maintained in REF over time. Heating oil also supplies 29% of the total, although more than half is phased out over time in REF as electricity increases its share. In NZ50, in contrast, wood disappears by 2050 and electricity increases to 90% of the total by 2050. Combined with a small quantity of thermal solar, this results in a more efficient mix, with 22% less energy used than in REF in 2050.

Within Prince Edward Island's small industrial base most activities are tied to the manufacturing sector and an even smaller pulp and paper operation. In NZ50, the energy mix evolution brings more electricity, largely in replacement of natural gas in manufacturing (54% of the total in 2050, roughly double its current share). Bioenergy also plays a greater role in this sector (41% in 2050). The pulp and paper industry also sees a larger penetration of electricity, but in this case as a replacement of bioenergy.

Transport in Prince Edward Island retains a higher level of oil products than the national average. This share is 54% in 2050 in REF, compared with 45% nationwide. Even in NZ50, this level remains high at 39%, compared with 15% nationally. These percentages are largely due to the fact that marine transport plays an extra-large role in the province's consumption and, as is the case nationally, decarbonization is limited in this sector. Even in NZ50, consumption for marine transport rises 25% by 2050 (+53% in REF), with only a small penetration of bioenergy.

Otherwise, the transport sector is largely decarbonized from the complete electrification of small to medium vehicles and public transit, as well as a contribution from hydrogen in large trucks, with the rest deriving from electricity. This results in a total consumption that is less than half the level in REF for 2050.

Figure 5.9a – Total GHG emissions by sector – Prince Edward Island

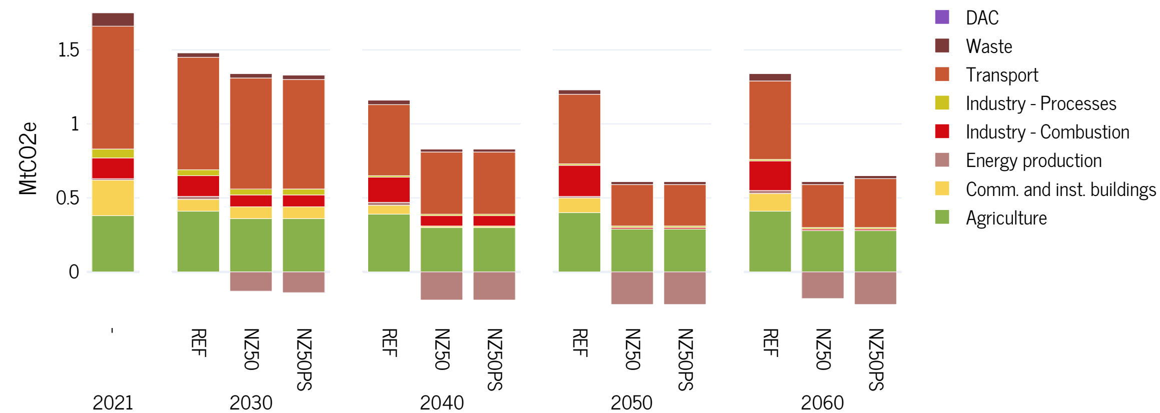
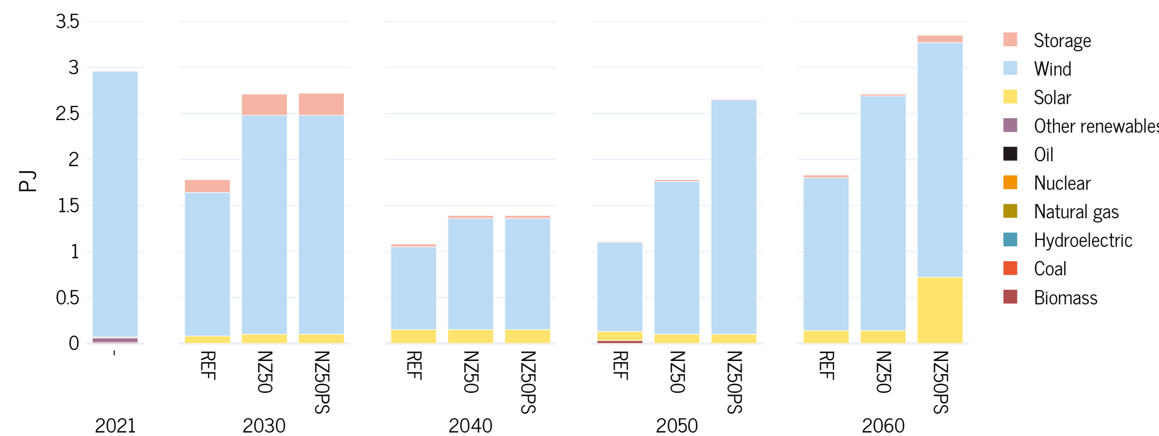


Figure 5.9b – Electricity generation by source – Prince Edward Island



2. How does primary and secondary energy production evolve in the province?

Primary energy production is very limited in Prince Edward Island, with only 3 PJ of wind electricity and 3 PJ of biomass feedstock (wood and black liquor from the pulp and paper facilities). Although little change is expected over time in REF, production grows by 50% in NZ50, resulting in more wood biomass and agricultural residues (Figure 5.9c).

While in NZ50 a very small hydrogen production increases over time to 0.5 PJ, the only sizeable increase in secondary energy production is from biomass, which reaches 6 PJ in 2050 (NZ50) compared to zero today (Figure 5.9d).

3. What is the extent of electrification and how does the electricity generation mix compare with the national average?

Despite extensive electrification, as observed in other provinces, Prince Edward Island's electricity production decreases over time, with levels 40% lower than today in 2050 for the NZ50 scenario, from 3 PJ to less than 2 PJ in 2050 (Figure 5.9b). Electricity consumption still climbs 64% in REF and 122% in NZ50, but a greater share of these needs is met by production imported from New Brunswick. Production levels within Prince Edward Island are much higher in NZ50PS than in NZ50, as a lower SMR deployment in New Brunswick in the scenario leads to higher costs for imports, resulting instead in more wind and solar deployment in 2050 and 2060.

4. How does biomass production and use evolve?

With the small exception of black liquor used in heat boilers, most biomass in the province is currently used for space heating. In net-zero scenarios, this situation changes over time as wood is no longer used for space heating and the increased quantities of biomass are transformed into syngas and biochar, providing some negative emissions. By 2050, this is the case for 98% of wood biomass produced in the province (Figure 5.9f).

Figure 5.9c – Primary energy production – Prince Edward Island

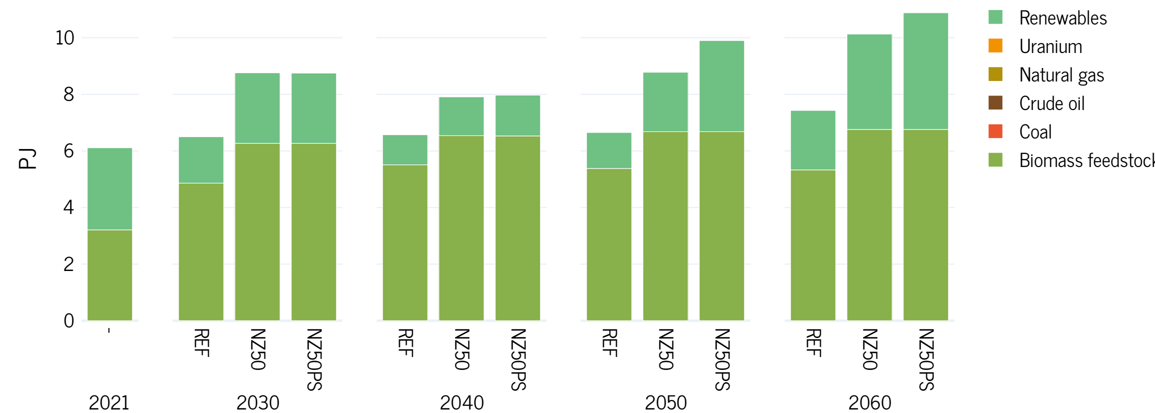
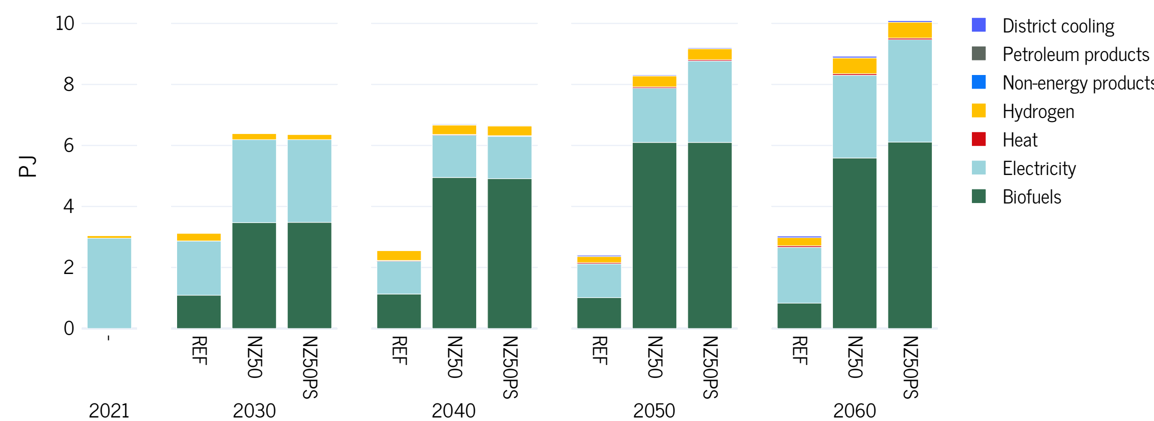


Figure 5.9d – Secondary energy production – Prince Edward Island



5. How do the emissions trajectories compare to the national average?

Given the size of the province and its small industrial sector, emissions today are already limited at less than 2 $MtCO_2e$. In REF, these emissions decline by 30% before 2050 in particular owing to the electrification of transport (Figure 5.9a). In NZ50, this reduction reaches -78% by 2050, making the province slightly positive in net emissions. Emissions remaining in transport and agriculture, while around half of REF in 2050, remain greater than the negative emissions contribution of the biochar produced in the energy production sector. No direct air capture occurs in the province.

Bottom line: how does Prince Edward Island stand out from other provinces in the results?

Based on the above results, a few key differences between Prince Edward Island and the national average emerge:

- In net-zero scenarios, energy consumption in buildings moves away from the large share supplied by wood biomass and heating oil today.
- The proportion of oil products used in the transportation sector's energy mix is larger than the national average and remains so over time, even in NZ50, largely due to the great importance of marine transport.
- While electricity needs in the province rise significantly, as is the case nationally, most of the additional needs are met by production from SMRs in New Brunswick, a share that is sensitive to the assumptions on SMR deployment
- Wood biomass used for space heating goes to produce negative emissions from biochar in NZ50.
- Although emissions reductions in net-zero scenarios are substantial in the province, limited cost-effective opportunities to realize negative emissions applications and the absence of DAC lead to a slightly positive net balance.

Figure 5.9e – Final energy consumption by sector – Prince Edward Island

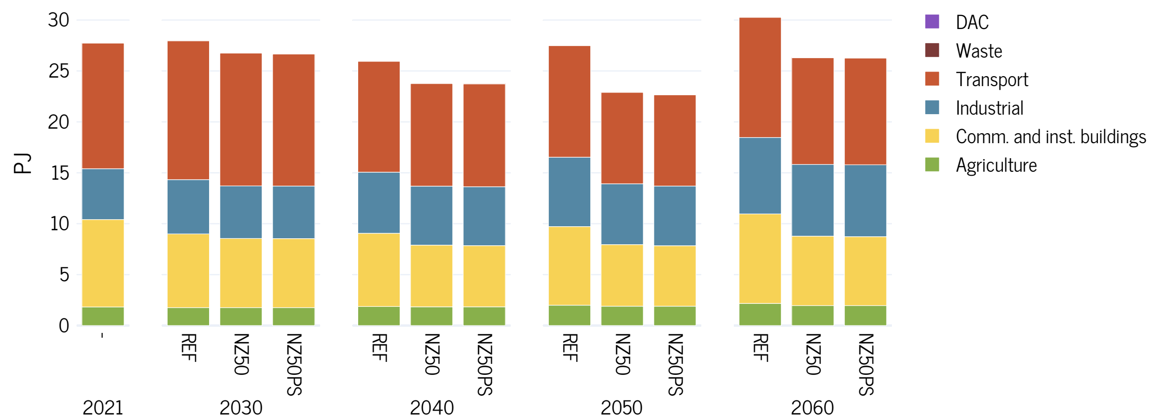
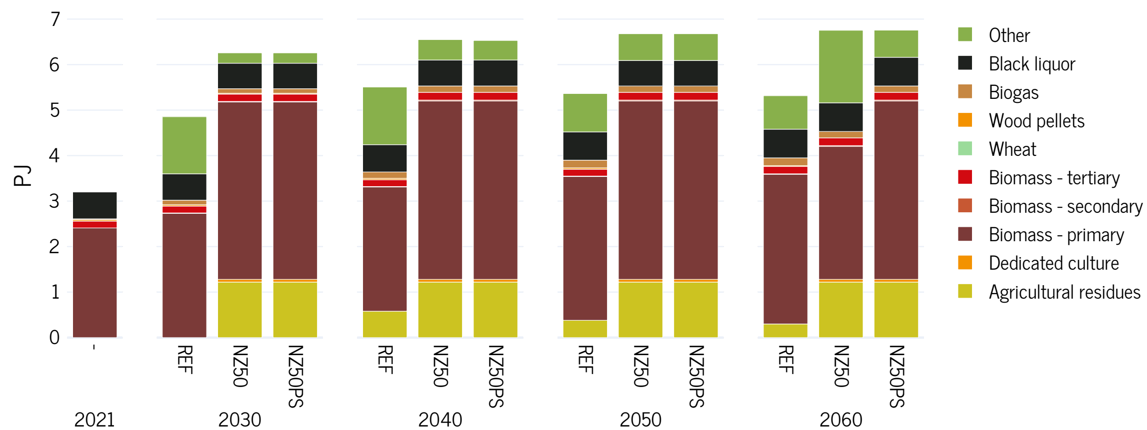


Figure 5.9f – Biomass feedstock used by type – Prince Edward Island



5.10 Newfoundland and Labrador

1. What are the main similarities and differences in energy consumption patterns across sectors?

Results for Newfoundland and Labrador show a greater decrease in total final energy consumption than the national average, especially in the reference scenario (Figure 5.10e). At 110 PJ, levels in REF for 2030 are similar to those of today and never rise over the rest of the time horizon considered, remaining at 80 PJ after a 23% drop between 2030 and 2040. NZ50 consumption levels decline more quickly than in other provinces, falling to 70 PJ in 2050, although a rebound occurs after 2050, with a 10% increase to 2060. As is the case for the other provinces, our modelling does not include future industrial projects, such as mining or green hydrogen production, that could have a significant impact on the total energy demand.

All this decrease in REF is due to lower consumption of oil products. This reduction is more significant in NZ50, accounting for part of the difference with REF, but electrification is more substantial in the net-zero scenarios and leads to a move away from natural gas as well, contrary to REF, where it actually increases over time.

Buildings evolve very similarly in REF and NZ50. Overall consumption falls 46% in all scenarios by 2050, from a similar transformation of the mix: heating oil, propane and kerosene, which combine to form 21% of today's consumption, are virtually eliminated, while district heating plays a marginal role next to the almost full electrification of buildings. The main difference between REF and NZ50 is the amount of bioenergy used, which remains at 6% in REF but is eliminated in NZ50. Efficiency improvements also contribute, with the end result that not only is total energy demand less than today, but also that even electricity use declines 23% by 2050 in this sector.

Industrial energy consumption increases in all scenarios after 2030, after a small drop in NZ50. By 2050, consumption is up 22% in REF, whereas NZ50 transforms the mix to reduce consumption to levels 8% higher than today's. This is largely due to more extensive electrification in NZ50 and the elimination of natural gas over time, in sharp contrast to REF, where it accounts for 20% of consumption in 2050. Coal also declines more rapidly in NZ50, but is nonetheless eliminated in REF by 2060. These differences are primarily due to transformations in the mining sector.

Figure 5.10a – Total GHG emissions by sector – Newfoundland and Labrador

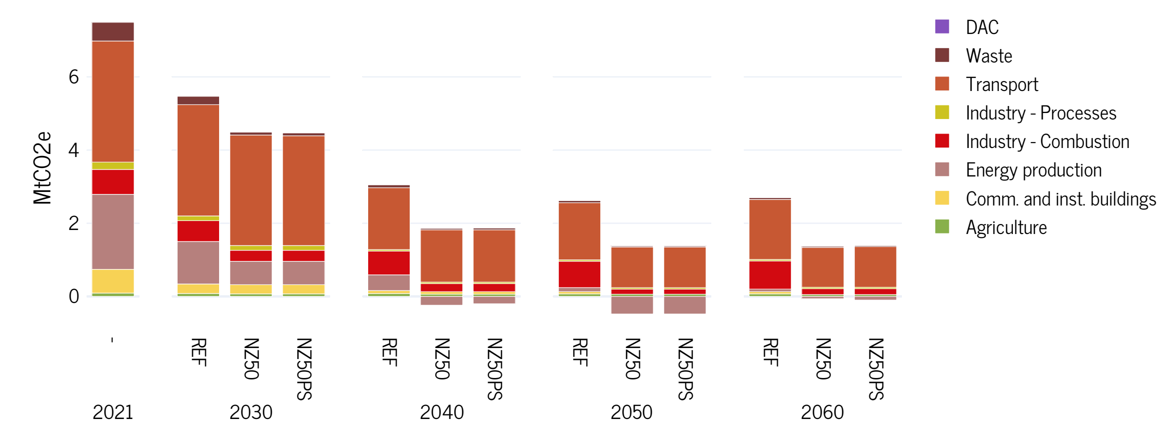
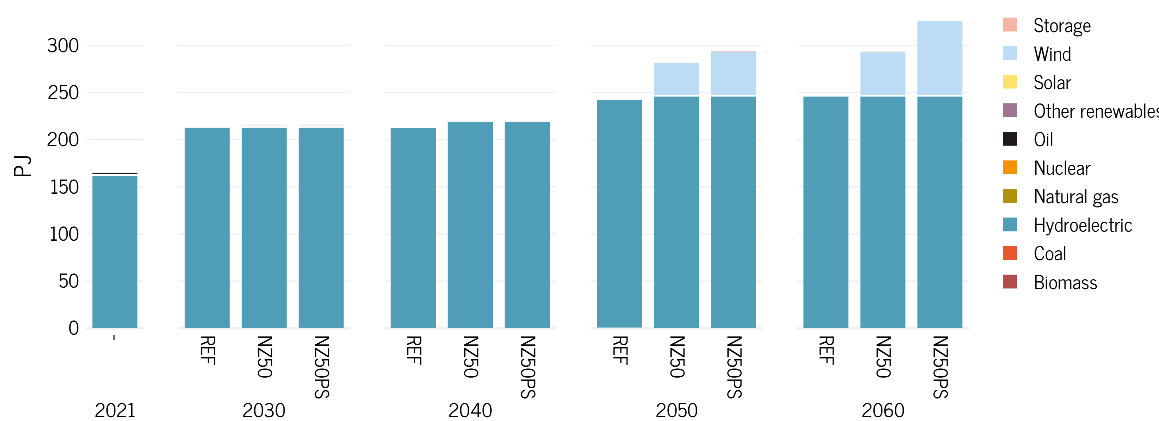


Figure 5.10b – Electricity generation by source – Newfoundland and Labrador



Consumption in the transportation sector is reduced in net-zero scenarios compared to REF, mainly due to a more extensive electrification of road transport: as in most other parts of the country, passenger transport is fully electrified, although freight transport remains largely dependent on oil products in 2050 in REF (71% of total consumption). NZ50 fully decarbonizes road freight transport by 2050, posting consumption levels less than half of REF's.

2. How does primary and secondary energy production evolve in the province?

Primary energy production in Newfoundland and Labrador consists mainly of crude oil extraction (590 PJ, or 75% of today's total) and hydroelectricity production. The former grows by 38% before 2030, while NZ50 imposes production cuts bringing levels down 19% (Figure 5.10c). NZ50 continues to rapidly lower this production and the gap with REF diminishes over time as production levels in the reference scenario are down 82% of current levels by 2050. The production of natural gas (20 PJ today) decreases at a similar pace in all scenarios, down 90% by 2040. As for biomass feedstock, the very low levels (10 PJ today) increase 50% by 2030 in all scenarios and remain similar thereafter.

Secondary energy production is limited to electricity in the province, where generation increases 70% by 2050 in NZ50 (Figure 5.10d). Hydrogen production remains marginal across scenarios, especially in NZ50.

3. What is the extent of electrification and how does the electricity generation mix compare with the national average?

Electricity generation (Figure 5.10b) grows 30% in both REF and NZ50 by 2030, after which a gap is noted and the increase by 2050 is 70% in NZ50 (to 80 TWh) and 46% in REF (to 70 TWh). The entire growth before the 2040s comes from dam-equipped hydroelectric power plants, while net-zero scenarios use onshore wind for additional needs starting in 2050 (13% in NZ50 for 2050).

Figure 5.10c – Primary energy production – Newfoundland and Labrador

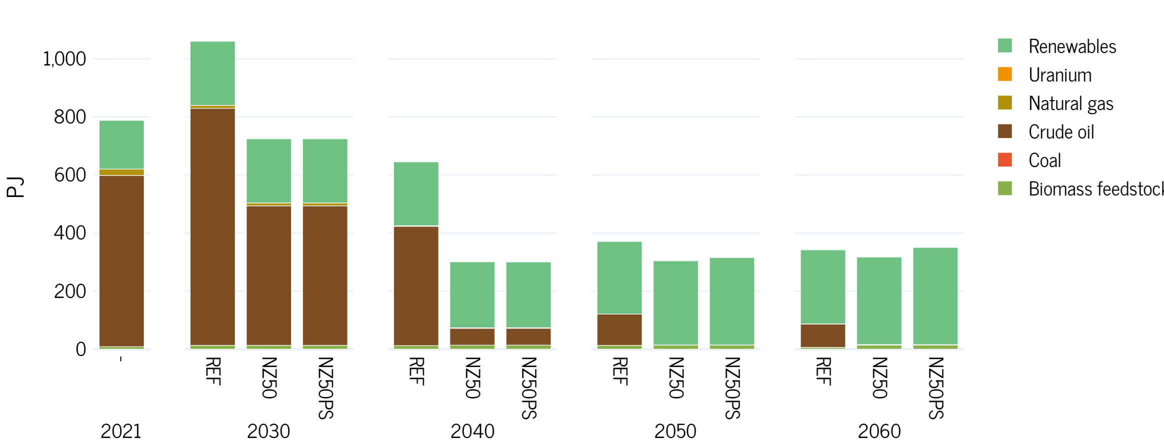
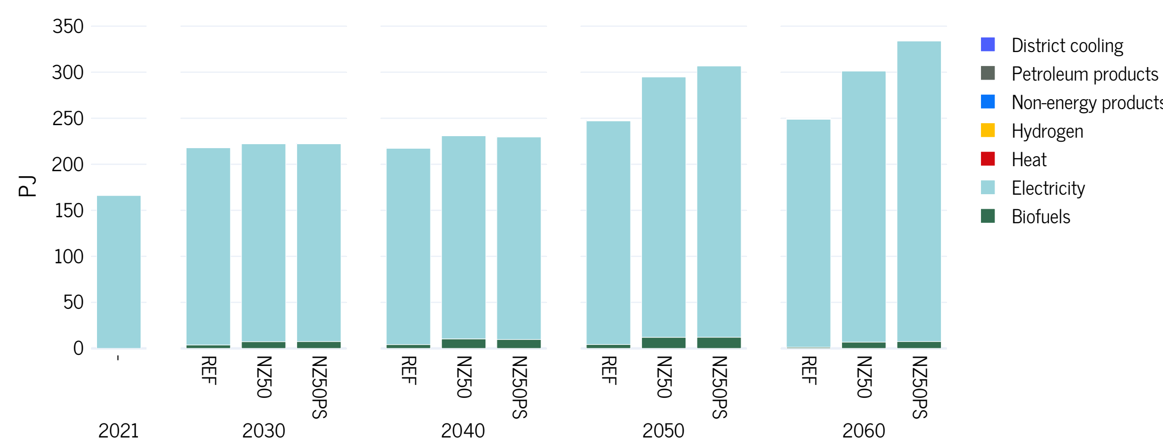


Figure 5.10d – Secondary energy production – Newfoundland and Labrador



4. How does biomass production and use evolve?

Biomass use in the province is limited. The 50% increase over time comes overwhelmingly from wood biomass, with the remainder deriving from a small quantity of biogas (Figure 5.10f). As in other provinces, the use evolves differently in NZ50 than in REF. Most wood biomass is currently used for space heating in residences. This changes rapidly in NZ50, as feed stock goes to syngas and biochar production instead, resulting in negative emissions from the operations. In REF, total quantities are back to today's levels by 2060.

5. How do the emissions trajectories compare to the national average?

Although Newfoundland and Labrador ends up with net positive emissions in 2050 in the net-zero scenario (Figure 5.10a), it manages to reduce its emissions by 90% from current levels, from 11 to 1 $MtCO_2e$. This is the result of virtually no emissions from agriculture or industrial processes in 2050 and very few negative emissions due to the absence of DAC and the marginal quantities of biomass available for BECCS or biochar. At 1 $MtCO_2e$, transport emissions are the only significant total remaining.

Bottom line: how does Newfoundland and Labrador stand out from other provinces in the results?

Based on the above results, a few key differences between Newfoundland and Labrador and the national average emerge:

- Decreases in total final energy consumption are more significant than the national average, especially in the reference scenario, largely as a result of lower consumption of oil products.
- More extensive electrification in NZ50, which helps eliminate natural gas, leads to a reduction in energy consumption from industry, in sharp contrast to REF, where this decline of natural gas does not occur.
- Both natural gas and crude oil production are eliminated over time, even in REF.
- The expansion of electricity production mainly occurs through additional hydro capacity, although NZ50 requires some wind production as well.
- The bottom line in 2050 emissions for the net-zero scenarios is almost uniquely driven by transport as other remaining sources are marginal and the contribution of negative emissions is also limited.

Figure 5.10e – Final energy consumption by sector – Newfoundland and Labrador

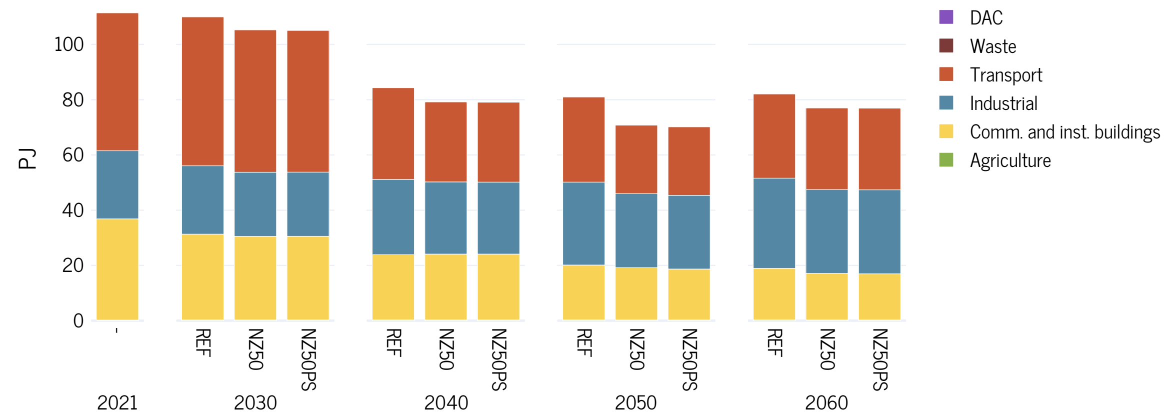
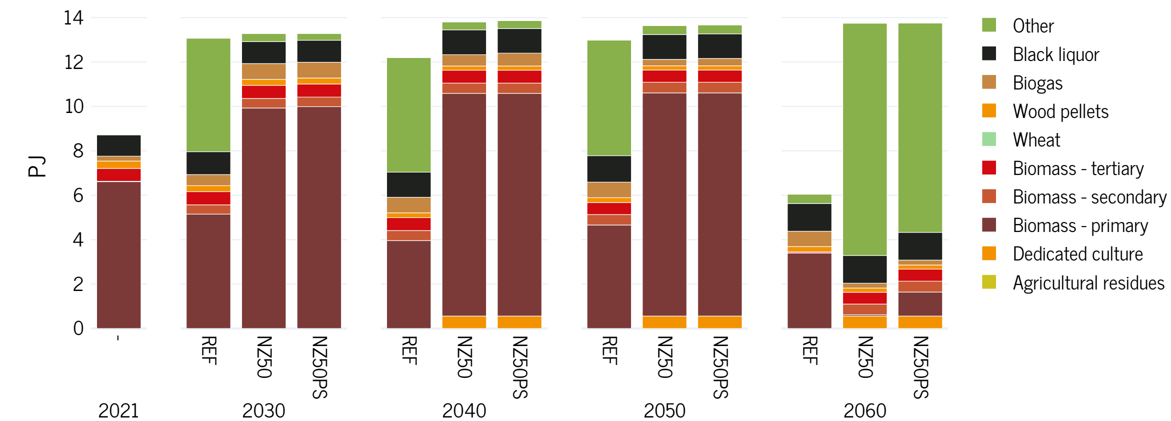


Figure 5.10f – Biomass feedstock used by type – Newfoundland and Labrador



5.11 Yukon

1. What are the main similarities and differences in energy consumption patterns across sectors?

Total final energy consumption in the Yukon presents a much smaller share of consumption from industry, given the limited size of the sector (Figure 5.11e). Furthermore, while consumption in buildings is relatively constant across the time horizon, transport emissions grow sharply before 2030 in all three scenarios, before dropping quickly in the 2030s due to the implementation of the ZEV mandate, although questions remain as to the availability of infrastructure to support this mandate in the Yukon and other northern regions. NZ50 eventually distances its consumption levels from REF, chiefly after 2040.

Electricity is already the main source of energy used in buildings (71% of the total), with bioenergy and heating oil making up the rest. Over time, electricity's share grows in NZ50, taking away from both sources but especially heating oil, which is eliminated by 2050. A small quantity of geothermal and district heating also contributes from 2040, although primarily in NZ50.

Nonetheless, the region's limited industrial energy consumption is transformed. Overall consumption for the sector almost doubles by 2030, driven mainly by an increase in the use of electricity and bioenergy. This is the result of a larger mining sector and some additional manufacturing operations. The evolution of this consumption does not greatly differ in REF and NZ50.

Energy consumption in the transportation sector is halved by 2050 in NZ50, essentially as the result of the full electrification of both passenger and road freight transport by 2050. No rail or marine transport is present in the territory. The contrast with REF is sharp as almost no freight transport is decarbonized in the reference scenario.

Figure 5.11a – Total GHG emissions by sector – Yukon

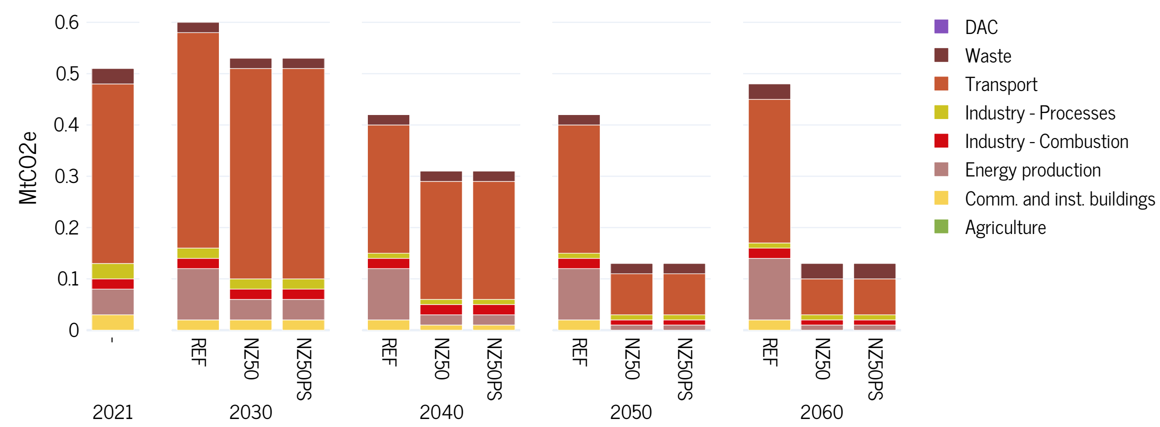
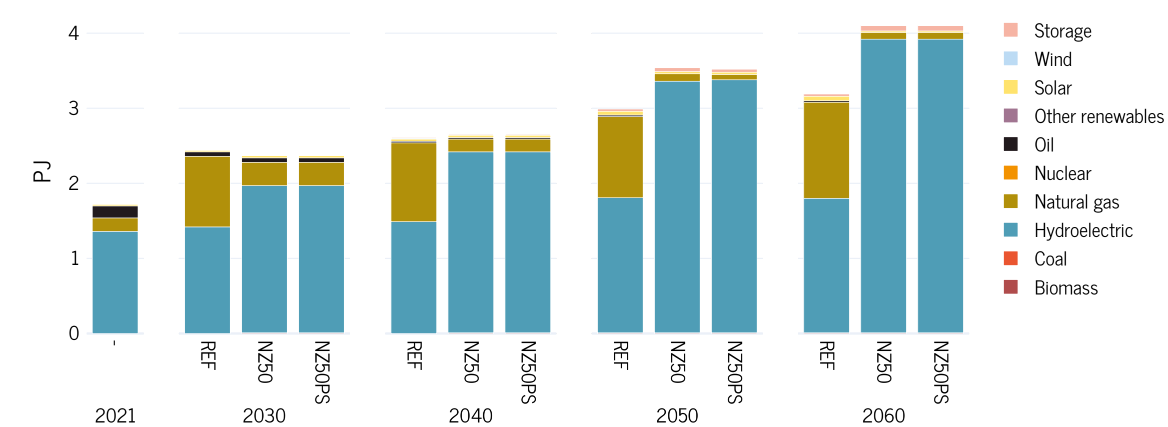


Figure 5.11b – Electricity generation by source – Yukon



2. How does primary and secondary energy production evolve in the territory?

Since no fossil fuels are extracted in the Yukon, primary energy production (Figure 5.11c) is limited to a very small quantity of biomass feedstock (200 GJ) and a few hydroelectric facilities (1,400 GJ). The evolution of biomass is identical across scenarios, doubling quantities by 2030 and increasing a further 36% until 2050. The differences between net-zero pathways compared and the reference scenario are limited to the overall quantity of primary electricity produced.

A similar pattern is observed for secondary energy production (Figure 5.11d), where electricity is the only source produced today and increases significantly in both REF and NZ50 (albeit more so in the latter). A very small quantity of district heating and cooling appears over the longer term.

3. What is the extent of electrification and how does the electricity generation mix compare with the national average?

After a rapid increase (40% by 2030, from 0.5 to 0.7 TWh), electricity doubles by 2050 from today's levels in NZ50, to 1.0 TWh (Figure 5.11b). The increase in REF is smaller although still substantial (+72%). However, the important difference on the short term is that a new hydroelectric power plant comes online in the NZ50 scenario by 2030, supplying 23% of the total in 2030, along with some additional natural gas power. In REF, all the increase to 2030 comes from natural gas.

For the rest of the time horizon considered, hydroelectric production plays the main role, both in REF (after 2030) and in NZ50, through further expansions. By 2050, hydroelectric dams become the most important, providing more than half of NZ50's production levels.

4. How does biomass production and use evolve?

As mentioned above, biomass feedstock production evolves similarly in REF and net-zero scenarios. Bioenergy production uses wood biomass as the main feedstock, with a very small production of biogas as well. The only distinction between the reference and net-zero scenarios is noted from 2050, where a larger share of the total wood biomass is used in manufacturing plants in net-zero scenarios, while REF makes use of this energy for commercial buildings consumption (Figure 5.11f).

Figure 5.11c – Primary energy production – Yukon

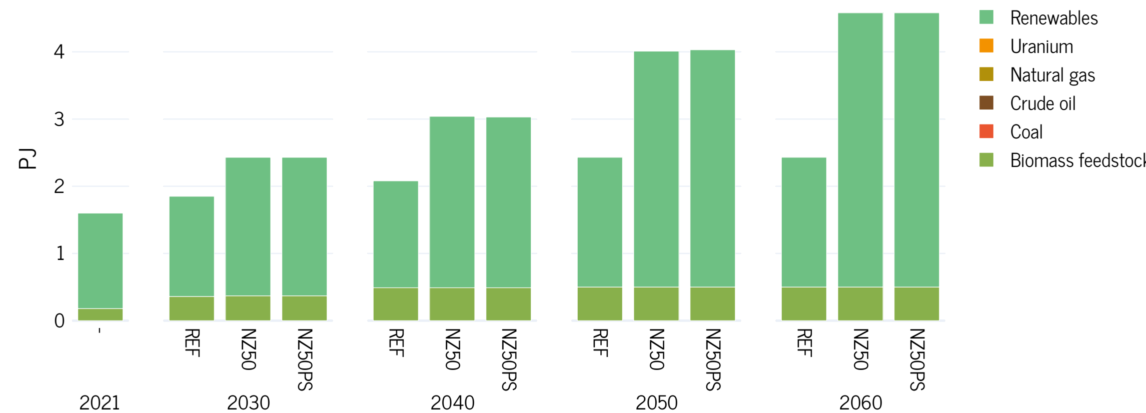
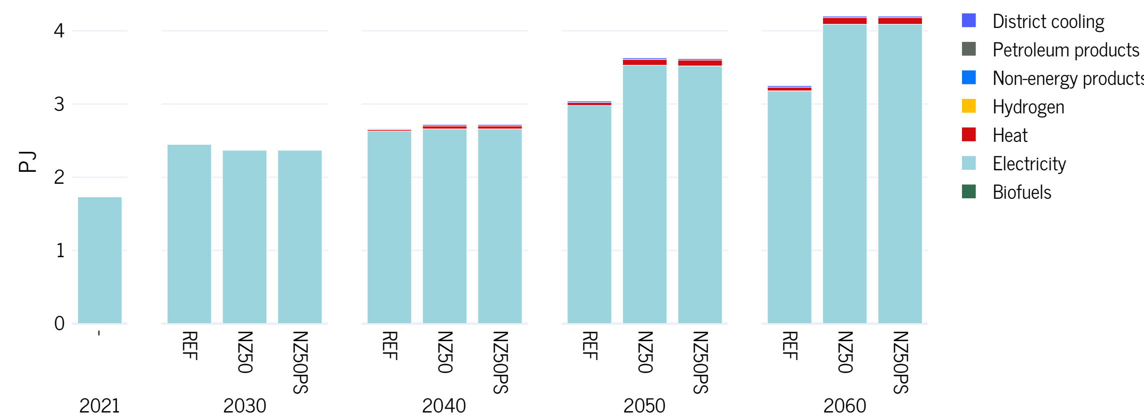


Figure 5.11d – Secondary energy production – Yukon



5. How do the emissions trajectories compare to the national average?

Emissions are reduced by only 15%, from 0.50 to 0.43 $MtCO_2e$, in the reference scenario by 2050 (Figure 5.11a). In NZ50, no sector posts net negative emissions in the Yukon as no BECCS is applied and no biochar is produced. Neither is there any direct air capture. As a result, the emissions reductions over time amount to 73% of today's levels.

Nonetheless, energy production and transportation, the two sectors representing by far the main sources of emissions today (10% and 69%, respectively), are significantly reduced: energy production emissions are virtually eliminated and transport emissions decrease 77% by 2050 in NZ50. This scenario is quite different from REF, where energy production emissions double by 2050 as a result of additional natural gas-fired electricity generation and transport emissions decline by only 29%. This gap illustrates the need for transformative measures tailored to the territory. Emissions from waste management also remain the same, contrary to the national average.

Bottom line: how does the Yukon stand out from other provinces and territories in the results?

Based on the above results, a few key differences between the Yukon and the national average emerge:

- REF shows no decarbonization of freight transport, while this transformation is substantial in NZ50, leading to important emissions cuts and reductions in energy consumption for the sector.
- Primary energy production expansion is limited to electricity and biomass in NZ50 but emissions from the sector grow to become the main source in REF due to a significant growth in natural gas-fired electricity generation.
- While natural gas-fired electricity generation expands before 2030 in REF, all scenarios see hydroelectricity drive most of the increase in electricity production over time.
- Emissions are reduced by only 15% in the reference scenario by 2050. In NZ50, no sector posts net negative emissions in the Yukon as no BECCS is applied and no biochar is produced.

Figure 5.11e – Final energy consumption by sector – Yukon

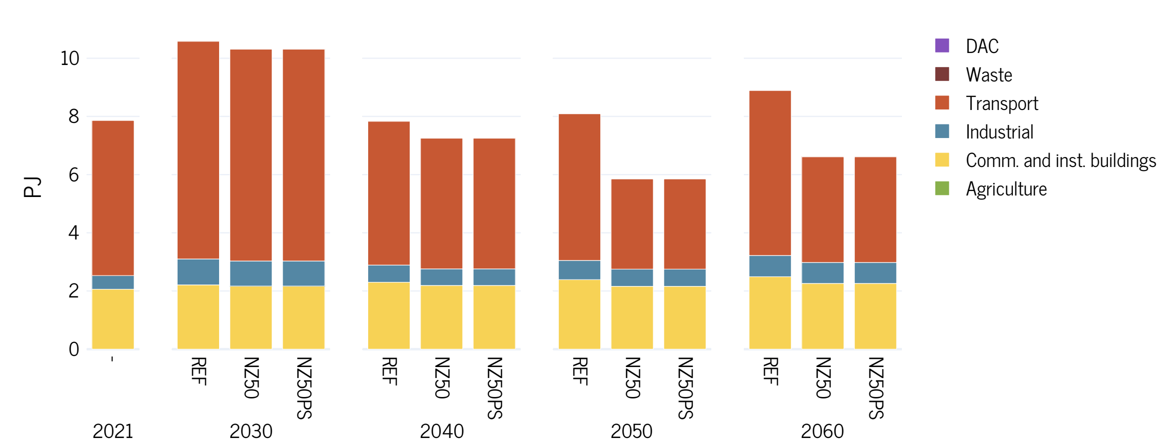
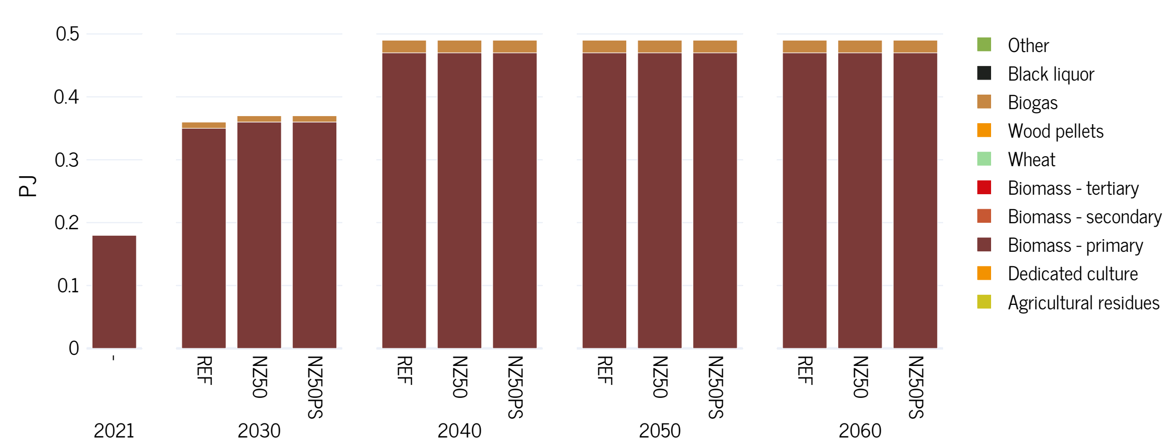


Figure 5.11f – Biomass feedstock used by type – Yukon



5.12 Northwest Territories

1. What are the main similarities and differences in energy consumption patterns across sectors?

Energy consumption in the Northwest Territories increases 20% by 2030, from 14 PJ today to 16 PJ, before declining in the 2030s, after which it rises again in REF (Figure 5.12e). Similarly to the rest of the country, an increase by 2030 is also noted in NZ50, although to a lesser extent, and the net-zero scenarios show a rapid decrease after 2030. This consumption only increases again after 2050, when it reaches a minimum of 11 PJ.

As in the other two territories, total final energy consumption in the Northwest Territories reflects a much smaller share of consumption from industry (3% today), owing to the sector's small size. Furthermore, while consumption in buildings is relatively constant across the time horizon, transport emissions grow sharply before 2030 in all three scenarios and then drop quickly in the 2030s due to the implementation of the ZEV mandate.

Buildings today show an eclectic energy mix, with electricity (31%), biomass (23%), light fuel oil (26%) and propane (18%) supplying most of the energy. In REF, consumption increases over time but electricity and natural gas both grow in importance, unlike fuel oil, which is almost eliminated. This contrasts sharply with the net-zero scenarios, where electricity grows to 62% of the total by 2050. Net-zero scenarios also result in the elimination of biomass, natural gas and most of propane and heating oil, as electricity is complemented by hydrogen and district heating to meet needs.

Nonetheless, the territory's limited industrial energy consumption is transformed in net-zero scenarios. Natural gas currently supplies 86% of this energy, a share that remains constant over time in REF as total consumption grows by 50%. In NZ50, electricity becomes the main source to replace natural gas, increasing after 2040 to reach 37% of consumption in 2050 and 57% in 2060. Consumption is overwhelmingly driven by the mining sector.

Energy consumption in the transportation sector is down 36% by 2050 in NZ50 as both passenger and road freight transport are fully decarbonized, with a small share of the former supplied by hydrogen and the rest by electricity. REF takes a completely different direction, with oil products retaining a 60% share of the total in 2050 and hydrogen playing a greater role than electricity.

Figure 5.12a – Total GHG emissions by sector – Northwest Territories

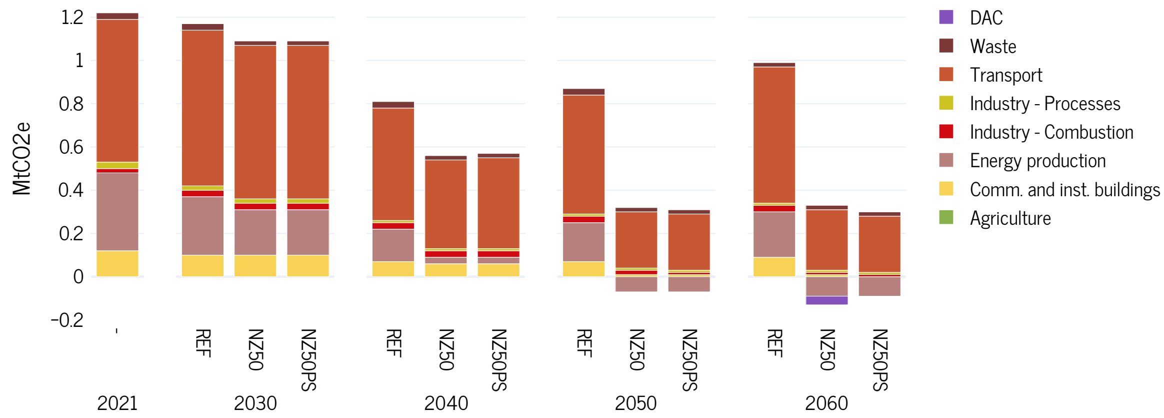
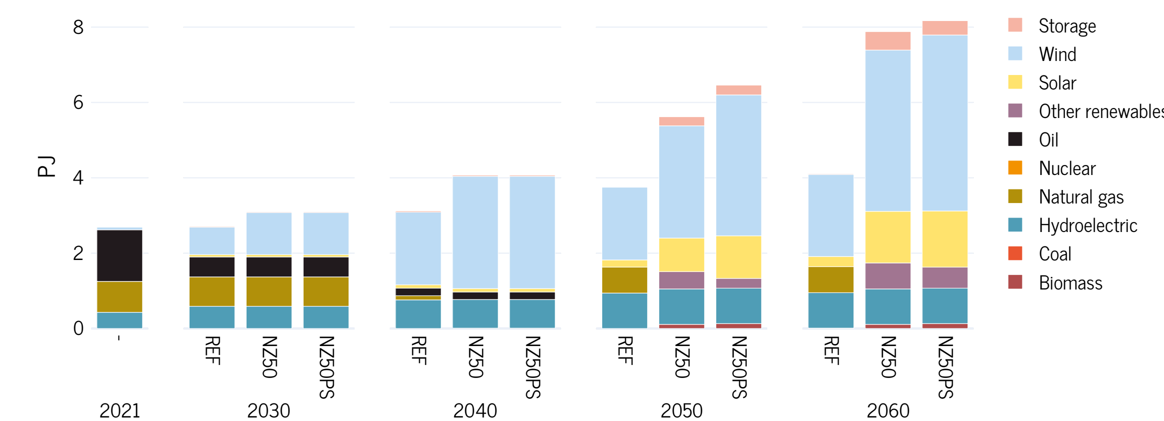


Figure 5.12b – Electricity generation by source – Northwest Territories



2. How does primary and secondary energy production evolve in the territory?

A small production of crude oil represents 75% of primary energy production in the Northwest Territories. This production is terminated after 2030 in all scenarios (Figure 5.12c). The region's even smaller natural gas production declines across scenarios, while renewable electricity increases sixfold in REF and tenfold in NZ50 by 2050. Biomass feedstock production grows 41% in REF and 59% in NZ50 by 2050. However, unlike in the rest of the country, this increase is progressive over the entire period.

Current secondary energy production is limited to electricity (3 PJ), which doubles by 2050 in NZ50 (Figure 5.12d). Over time, other forms, including heat and hydrogen, come to be produced in all scenarios.

3. What is the extent of electrification and how does the electricity generation mix compare with the national average?

Although electricity production growth is slow in REF, it nevertheless amounts to 40% over current levels by 2050, at 1 TWh vs. 0.75 TWh today (Figure 5.12b). Expansion is much more significant in NZ50, with 15% more as early as 2030 and more than doubling to 1.6 TWh by 2050. Current production derives mainly from light fuel oil (51%) and natural gas (30%), both of which are reduced by over 80%. None of the above is the result of the CER since the modelling assumes it is not applied in the territories (see policy assumptions in Appendix A).

Wind replaces most of this capacity, reaching a little over half of the total in 2050 for all scenarios. This is balanced by a more than doubling of hydro production by 2050. Given additional contributions from tidal and solar in the net-zero scenario to achieve the larger total quantities, storage also plays a role in these scenarios.

4. How does biomass production and use evolve?

The increase in biomass production is in the form of more wood biomass (+50% by 2050), which evolves rather differently than in most of the rest of the country as none of this feedstock is used to produce biochar (Figure 5.12f). Instead, it grows as a fuel source for space heating before 2040. After that, net-zero scenarios rapidly eliminate it from buildings and use the quantities for a roughly equal quantity of BECCS electricity and hydrogen production (0.5 PJ each), starting in 2050.

Figure 5.12c – Primary energy production – Northwest Territories

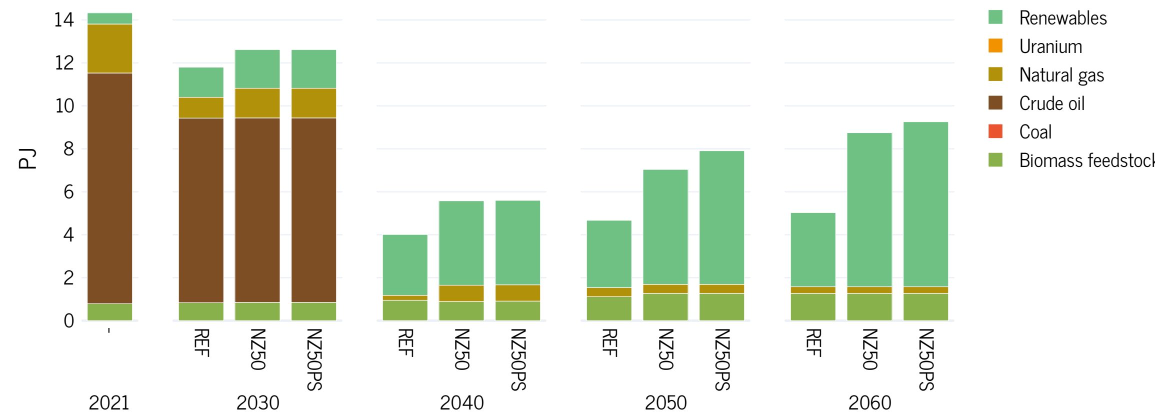
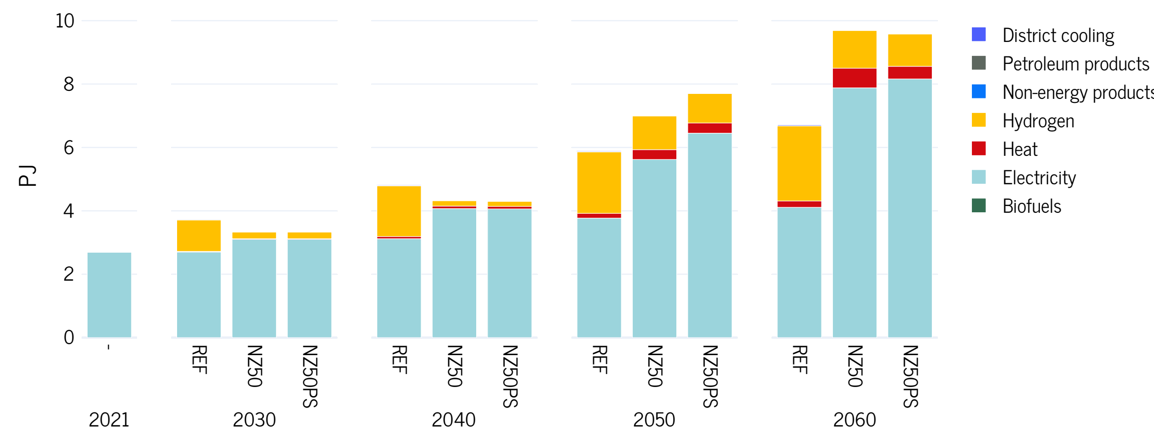


Figure 5.12d – Secondary energy production – Northwest Territories



5. How do the emissions trajectories compare to the national average?

By 2050, emissions are reduced by 29% in the reference scenario, although growth in energy consumption after 2050 leads to an increase in emissions (Figure 5.12a). In NZ50, the energy production sector manages to produce a small quantity of negative emissions, resulting from BECCS electricity and hydrogen production. Emissions in NZ50 for 2050 remain at 20% of today's levels. In these scenarios, buildings eliminate more than 90% of their emissions and transport segments cut theirs by 60%.

Bottom line: how do the Northwest Territories stand out from other provinces and territories in the results?

Based on the above results, a few key differences between the Northwest Territories and the national average emerge:

- REF decarbonization in freight transport is primarily limited to hydrogen, while in NZ50 electrification is substantial and leads to larger emissions cuts and reductions in energy consumption for the sector.
- Crude oil production is eliminated both in REF and in NZ50 before 2040.
- As in other jurisdictions, negative emissions from bioenergy play an important role, although this role is tied solely to BECCS energy production and no biochar is produced.
- Wind energy drives the significant growth in electricity production, with other renewable sources, including hydrogen and district heating, playing a role in NZ50 as well.
- Emissions from the Northwest Territories decline 80% in the net-zero scenario, with a contribution from BECCS.

Figure 5.12e – Final energy consumption by sector – Northwest Territories

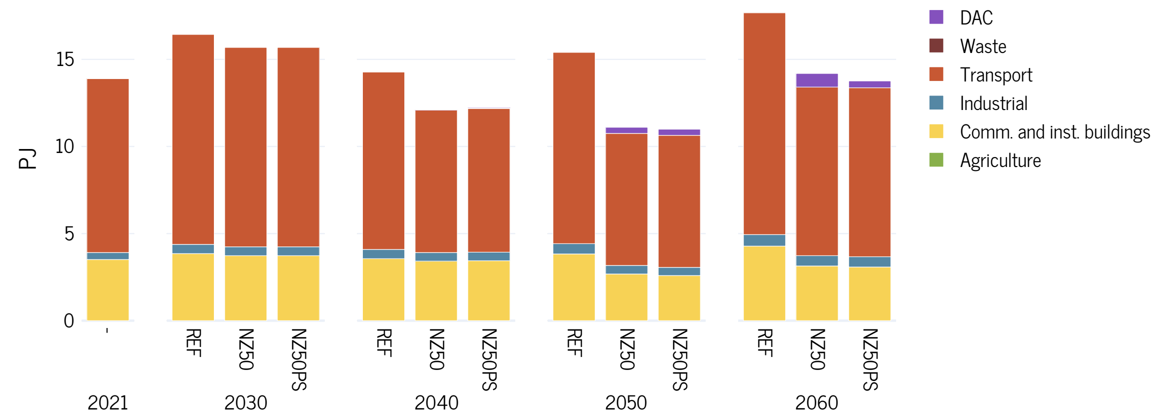
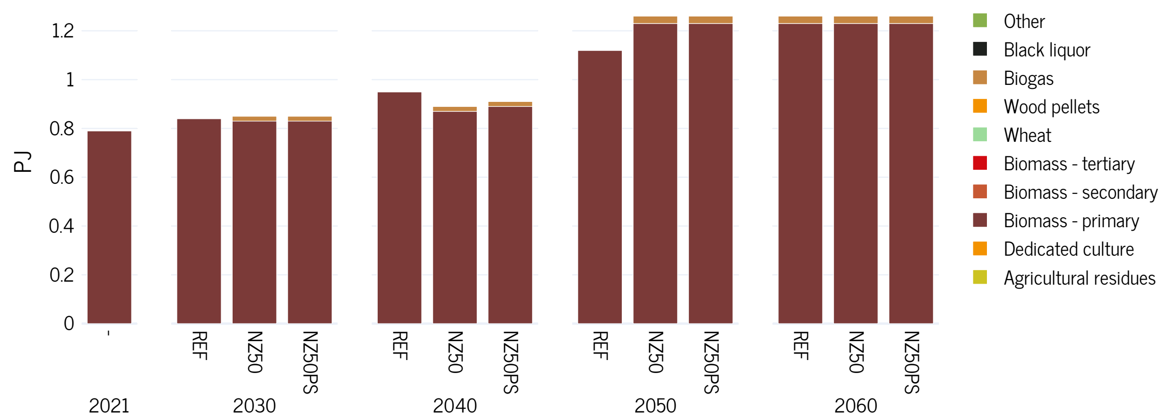


Figure 5.12f – Biomass feedstock used by type – Northwest Territories



5.13 Nunavut

1. What are the main similarities and differences in energy consumption patterns across sectors?

The evolution of final energy consumption in Nunavut varies from that of the other territories since all scenarios present a continuous increase over time, up from 3.6 PJ today (Figure 5.13e). While REF levels distance themselves from net-zero scenarios from 2030, after 2050 the gap shrinks, with 5.6 PJ for NZ50 and 5.7 PJ for REF in 2060. Industrial activity is almost nil in the territory and has little impact on overall consumption.

Today, buildings consumption is almost entirely supplied by electricity and this mix does not change over time. After a decrease in energy needs before 2030, due to efficiency improvements, consumption increases again to reach levels similar to today's by 2050.

Nunavut's needs in the transport sector are different than those in the rest of the country: road transport (passenger and freight) is limited to 28% of total energy consumption for the sector today as off-road and air transport needs are much more substantial (in relative terms) than in most other parts of the country. Transformations are also limited to road transport, making the impact on total consumption less than the national average; both REF and NZ50 show higher overall consumption levels in 2050 (+41% and +17%, respectively). Hydrogen plays no role in the full decarbonization of road transport, which is exclusively carried out through electricity. Similarly to the situation in the other territories, questions remain as to the availability of the appropriate infrastructure for this deep transformation.

Figure 5.13a – Total GHG emissions by sector – Nunavut

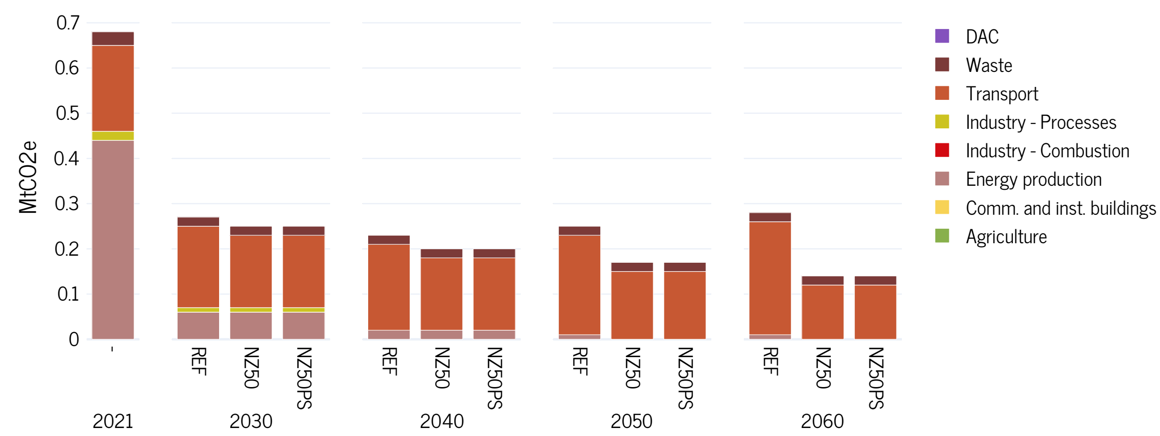
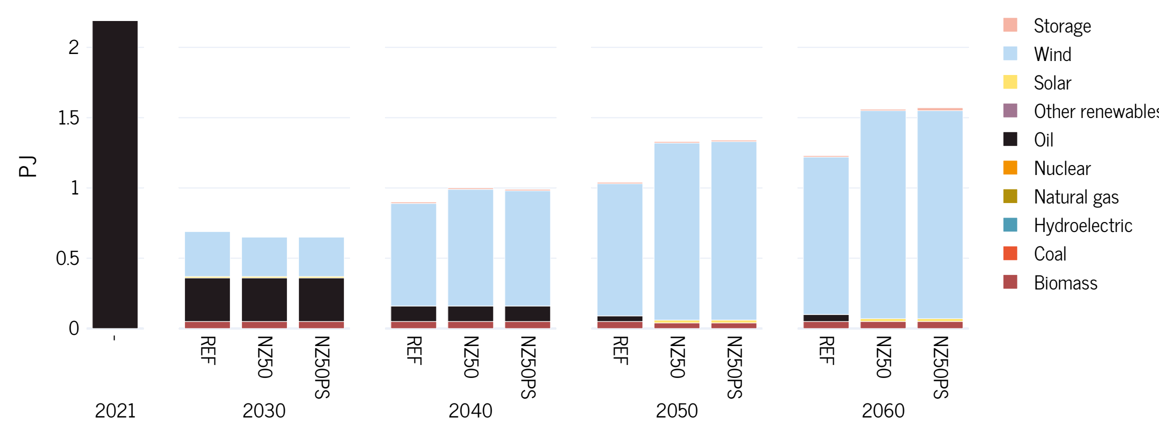


Figure 5.13b – Electricity generation by source – Nunavut



2. How does primary and secondary energy production evolve in the territory?

Since no fossil fuels are extracted in Nunavut, primary energy production is limited to negligible quantities of biomass and renewable electricity (Figure 5.13c). The evolution of biomass is identical across scenarios (multiplying quantities by 20 before 2030 staying at similar levels until 2050). The difference between net-zero pathways compared and the reference scenario are limited to the overall quantity of primary electricity produced.

A different pattern is observed for secondary energy production, where electricity is the only source produced today and decreases significantly in both REF and NZ50, although less so in the latter (Figure 5.13d). A very small quantity of district heating and cooling appears over the longer term.

3. What is the extent of electrification and how does the electricity generation mix compare with the national average?

From 2 GWh today, electricity production almost doubles in net-zero scenarios by 2050 while increasing 50% in REF (Figure 5.13b). There is no distribution grid in the territory and most generation currently comes from light fuel oil generators. Over time, this generation shifts almost exclusively to wind with a small storage capacity, both in REF and in NZ50.

4. How does biomass production and use evolve?

Bioenergy production comes almost solely from wood biomass used for small electricity production facilities. After a large relative increase before 2030 (200 GJ in all scenarios from 10 GJ today), this production remains the same across scenarios over time (Figure 5.13f), serving as baseload to support the expansion of wind electricity production while producing fewer emissions than light fuel oil generators.

Figure 5.13c – Primary energy production – Nunavut

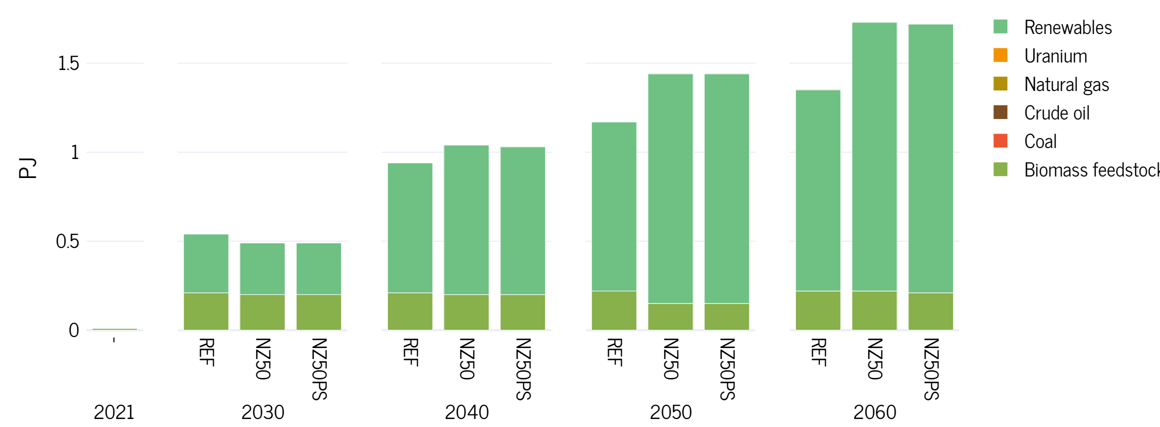
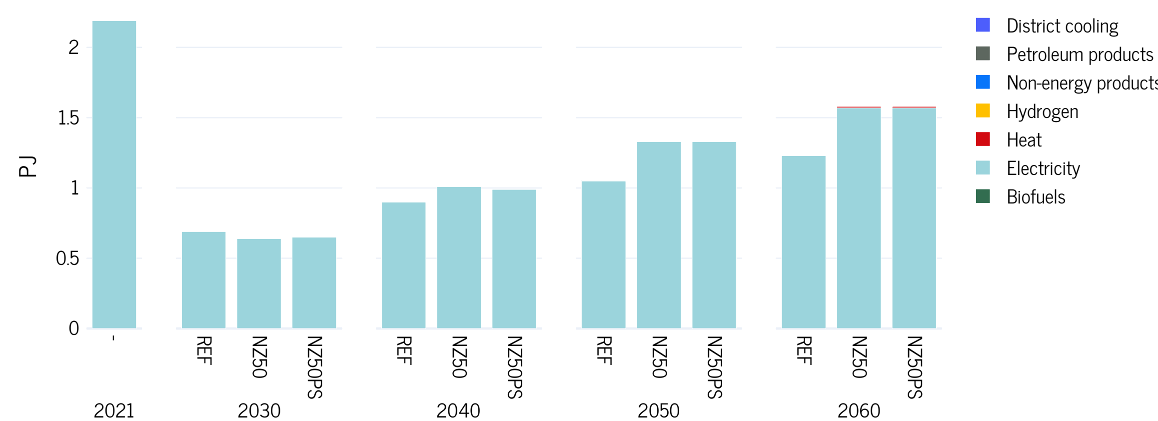


Figure 5.13d – Secondary energy production – Nunavut



5. How do the emissions trajectories compare to the national average?

Most emissions in Nunavut currently come from light fuel oil-fired electricity production (65%) and transport (28%). Since the rapid replacement of the electricity generation capacity across all scenarios dramatically reduces emissions in this sector, transport drives the overall emissions trend, especially after 2030 (Figure 5.13a). The more extensive decarbonization of vehicles in NZ50 leads to total emissions for Nunavut that are 30% lower than in REF in 2050, and 75% lower than today.

Bottom line: how does Nunavut stand out from other provinces and territories in the results?

Based on the above results, a few key differences between Nunavut and the national average emerge:

- Given that most buildings energy needs in Nunavut are supplied by electricity, the decarbonization of the energy mix in Nunavut is almost exclusively tied to transport and off-grid electricity production.
- The electricity production mix is decarbonized over time in the reference and net-zero scenarios as wind energy provides a cost-effective way to replace expensive fuel imports to remote regions, even taking into account the high cost of electricity storage to support this variable generation.
- However, decarbonizing the transport sector is a significant challenge as a much larger share of the sector' energy needs are for air and marine transport, where low-carbon options are more expensive.

Figure 5.13e – Final energy consumption by sector – Nunavut

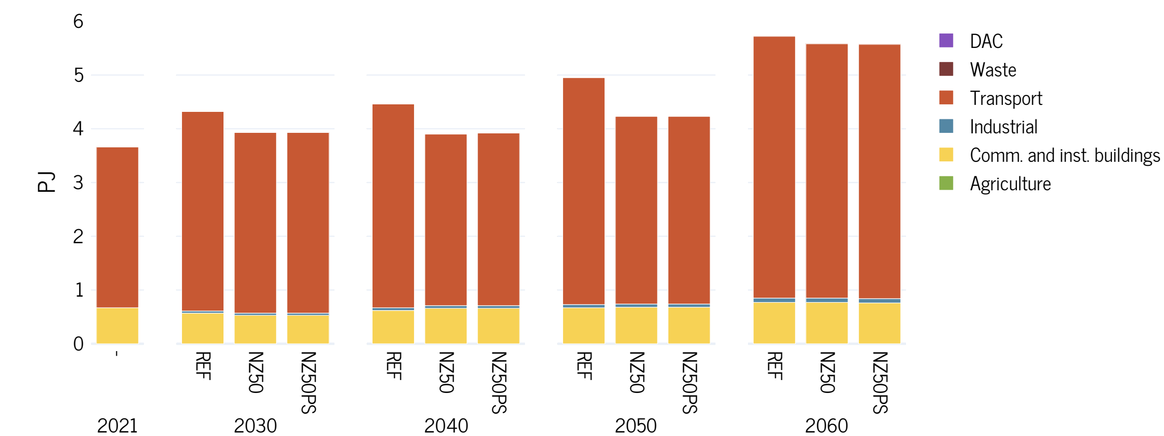
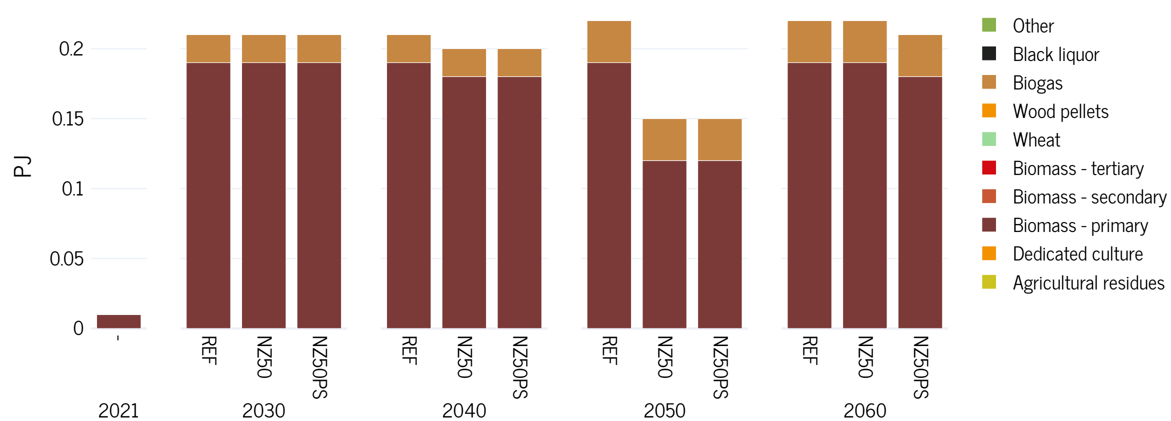


Figure 5.13f – Biomass feedstock used by type – Nunavut



5.14 Takeaways

The provinces and territories each face different challenges to be met in net-zero pathways. The results presented in the previous chapters must be understood as a national optimization and a closer look is necessary to assess the subnational challenges in meeting the resulting national projections. In turn, this closer look must take into account the variations in the energy systems in each province and territory and the very limited integration of these systems across provincial borders.

One straightforward observation is that **despite the considerable importance of emissions compensation (through negative emissions technologies in particular), all provinces must very significantly decarbonize, irrespective of their starting point, for the net-zero objective to be achieved**. For instance, the outsized industrial emissions from oil and gas production relative to other economic sectors in Alberta and Saskatchewan all decline dramatically in net-zero scenarios, while provinces with diverse industrial sectors like Ontario, where no unique low-carbon solution can be applied, all result in similar reductions on a per sector basis. This once more highlights the importance of maintaining emissions compensation solutions only for the sectors, such as agriculture, industrial processes, and air, marine and off-road transport, that are the hardest-to-abate.

Despite the above it is also noteworthy that the above challenges are uneven across provinces when it comes to developing the energy production capacity to support the transformations. Above all, **provinces where there is little hydroelectric baseload generation face more important grid infrastructure development issues**. Recent commitments made by some provinces toward expanding nuclear power generation, which is cheaper on paper than current storage technologies, make it a potentially important source as an alternative to hydroelectricity baseload when the latter potential is limited. However, uncertainties inherent in this particular technology and social acceptability issues considerably cloud the future of this deployment.

A third observation is that recent policy and regulatory measures result in extensive transformations on the short to medium term, especially in passenger transport, space heating and electricity production. However, it must be noted that **the majority of these expected transformations are the direct result of federal action, while provincial measures remain more uneven, limited and less transformative**. As further GHG reductions will require more and more demanding sectoral efforts, it is essential for provinces to deploy adapted structuring and efficient strategies as well.

Furthermore, while net-zero scenarios lead to national carbon emission neutrality by design, not all subnational jurisdictions meet the net-zero target as a result of the national optimization. **Cost optimization leads to a maximization of the potential for negative emissions technologies in some jurisdictions, for instance, leaving some minimal flexibility in achieving positive emissions balances in other provinces or territories.** One example is the positive net emissions balance of the three territories, where, despite limited emissions from industrial processes and agriculture, very small-scale negative emissions applications are more costly than compensating the remaining emissions elsewhere in the country where these applications can benefit from economies of scale.

The economics of emissions compensation also imply taking into account the resource availability to realize negative emissions with current information on technologies that have yet to be built at scale. For instance, British Columbia's considerable and readily available wood biomass resources are treated in the cost-optimization model as a cost-effective opportunity to produce negative emissions, which is even cheaper than fully decarbonizing some industrial sub-sectors in other provinces like Ontario or Quebec, for instance.

This implies that the true potential for realizing negative emissions at scale and building capacity to make this possible on the timescale required by the 2050 net-zero target must be determined as soon as possible. While the results for net-zero scenarios show a very large quantity of biochar, BECCS and DAC combining to make the pathway compatible with reaching net-zero, each and every one of these options remains to be developed at commercial scale.

A more realistic mapping of negative emissions potential is also essential given that the results for many provinces show that syngas production rapidly plays an important role before 2030, given the negative emissions from biochar that come as a by-product and the constraint to meet the 2030 GHG reduction target. However, after 2050, syngas production declines as increased hydrogen demand makes it more economical to achieve the negative emissions from BECCS hydrogen production rather than biochar. In practice, it is unlikely that the infrastructure buildout for syngas would happen so quickly before being phased out starting in the late 2040s. A careful assessment of how to deploy a mix of negative emissions technologies is thus essential in all provinces.

The modelling used in this Outlook is relatively conservative in terms of the potential for national or inter-provincial coordination on developing the energy system required by the net-zero target. Notably, jurisdictional tensions over energy management between provinces and the federal government should be actively eased by focusing on the fact that **there is considerable room for nationwide federal government programs to help tackle common challenges**. In particular, the transport sector faces similar difficulties across provinces and some cost tempering potential can be found in increased interprovincial electricity trade, making the transformation of electricity grids to simultaneously meet rising demand and decarbonize relatively easier.

6

Conclusions

Reaching net-zero requires profound transformation both within and beyond Canada's energy system. Natural resource endowment across the country opens up several possibilities for Canada to meet this challenge, notably through greater use of renewable electricity and uranium. Nevertheless, these possibilities require a massive buildout of infrastructure in conjunction with dramatically more efficient and productive energy use, as well as the abandonment of a very large part of the current energy production. Neither of these challenges is easy, but both will need to be met to create Canada's net-zero future.

This concluding chapter briefly highlights essential points of the evaluation of net-zero pathways derived from the scenarios modelled in this report, as well as what these results tell us when comparing them with a reference scenario that supposes limited new action to temper our impact on global warming.

6.1 Reaching net-zero by 2050

As the pandemic's effect on emissions waned and forest fires saw record years in 2022 and 2023, due in large part to global warming, efforts mainly led by the federal government have accelerated in Canada to initiate transformations toward a net-zero economy that would have a much more limited contribution to this climate change. In these efforts, the characteristics of Canada's energy production and consumption profile offer both challenges and advantages. The challenges include nationwide energy-hungry extraction and industrial sectors, a highly polluting transport sector, a strong economic regional dependence on fossil fuel production, and significant provincial disparity in addressing the energy transition. The advantages consist in an electricity sector being decarbonized at more than 80%, possession of the largest installed hydro reservoirs in the world, considerable potential resources for variable energy production, and substantial uranium and biomass resources.

6.1.1 What have we learned since the last Canadian Energy Outlook?

A comparison of the results presented in the preceding chapters with those obtained in previous edition of the Canadian Energy Outlook (Langlois-Bertrand *et al.* 2021) provides some insights into net-zero pathways in Canada. There are many points of convergence between the two editions: a very substantial increase in the role of electricity, a considerable reduction in crude oil production and natural gas use, and numerous negative emissions activities to compensate for remaining emissions. However, there are also some key differences that are noteworthy.

> **Even though recently announced or instituted measures bend the curve in the expected evolution of GHG emissions in the reference scenario, the net-zero target is still not reached by a wide margin.**

One important difference between the 2021 edition and this one is the impact of policy and regulatory measures enacted since 2021. The REF scenario now projects a 14% reduction by 2030 and 25% by 2050, compared with +3% and -18% respectively in the 2021 edition. While these results are contingent on the successful implementation of the Clean Electricity Regulations and the Zero-Emissions Vehicle mandate, an assumption we make in the REF scenario, this represents a departure from the GHG curve expected back in 2021 for the equivalent scenario. In other words, these measures narrow the gap, especially on the short term, between REF and NZ50. REF also shows that targeted measures have an impact; the ZEV mandate, for instance, in fact leads to a complete decarbonization of light-duty vehicles.

> **The provinces are not assuming their fair share of responsibility to decarbonize Canada's society.**

While the federal ZEV mandate overlaps with regulations in some provinces, most of the additional decarbonization of Canada's economy at the 2050 horizon stems from federal efforts, with few structuring efforts provided by the provinces. Given that energy comes under provincial jurisdiction, it will be impossible for Canada to achieve net-zero without a much greater involvement from provincial actors.

> **Bioenergy's role in net-zero pathways will likely be tied to negative emissions needs.**

A key difference with the 2021 edition is in the contribution of biomass. In this edition, biomass plays a much larger role early on, with a rapid increase of bioenergy in net-zero scenarios on the shorter term. After 2030, further consumption is limited due to resource availability and residual emissions, and biomass resources are diverted to the negative emissions activities in industry and energy production.

While BECCS applications were already strongly evident in the 2021 results, the inclusion of biochar as a negative emissions avenue, created as a by-product for the relatively versatile syngas, enables an early contribution that provides a temporal buffer for reductions. In other words, some reductions that are necessary on the short term are pushed a little further in time, while biochar allows for compensation of emissions in the meantime. The role of biomass, including those of biochar and BECCS options, is nevertheless complicated and fraught with uncertainty, not least because it is tied to its role as a decarbonization option outside the energy system in replacement of other materials.

Since 2021, there has been little progress in the deployment of CCS and DAC.

Despite their playing a major role in achieving net zero in our scenarios, uncertainty levels about carbon capture and sequestration applications, including negative emissions application, remain very high. Very few projects around the world have experimented with direct air capture or with most applications of BECCS on a substantial scale. NZ50 results must accordingly be treated with care as they assume that close to 25% of today's emissions would remain in 2050 and be compensated by capture and negative emissions using these options. Experience gained in attempting to scale up these technologies will be crucial over the next few years to better understand the possibilities at hand, or their limitations.

6.1.2 Thinking about 2030

Throughout this report, we explored potential transformations of Canada's energy sector through optimal techno-economic scenarios focused on Canada's GHG targets for 2030 and 2050. The results show that while reaching net-zero by 2050 is technically and economically achievable, it requires very deep changes in Canada's energy system. Given that half a decade is left before the 2030 checkpoint is reached, it is worth asking what can realistically be achieved before then as uncertainty is more limited on such a short time scale.

While NZ50 reaches the 2030 target by design, the gap with the expected evolution of emissions shown in REF suggests that, while it is almost technically impossible to reach Canada's goals for 2030, additional measures are urgently needed to set Canada on the path to net zero by 2050.

The REF scenario sees emissions falling by 14% from 2005 levels (to 632 from 730 $MtCO_2$, with only a 50 $MtCO_2$ reduction between 2021 and 2030). This reduction does not include potential reductions from nature-based solutions and the WCI credits imports from California, which are estimated by Environment and Climate Change Canada to total 45 $MtCO_2e$ (or a further 6% reduction) . Including these additional reductions, the REF scenario would therefore see a 20 % reduction (to 587 $MtCO_2$) by 2030, far smaller than the legislated 40% reduction target (439 $MtCO_2$) imposed in NZ50 (see Table 1). This major gap occurs even though REF includes the projected impact of announced measures such as the ZEV mandate and the Clean Electricity Regulations. To put it bluntly, unless a very major change of course is introduced on the very short term, essentially in the form of a 60% to 70% reduction in Canada's oil and gas production, we find that it is simply impossible for Canada to meet its 2030 target.

While other assessments of the progress so far toward the 2030 target, notably the Canadian Climate Institute's assessment (Sawyer et al. 2023), project more substantial reductions (which still fall well short of the target), a large part of these projections is contingent on further policy measures such as the proposed cap on emissions from oil and gas production and more stringent methane regulations. The final level of ambition of these measures, as well as whether they are implemented successfully and in time to have the projected impact, remain open questions for now.

A closer look at the projections for REF and NZ50 for 2030 reveals where the main difficulties lie. In some sectors, the projected pace of change in REF already shows major transformations. Thus the challenge would be to accelerate the pace, which is already fast, notably with regard to the buildout of new infrastructure. Electricity production, for instance, would need to be transformed at a much more rapid rate than what is expected as a result of the implementation of the CER and other drivers. In fact, the 2035 target date for the CER results in emissions very close to 0 in REF for 2035. In other words, the 36 $MtCO_2e$ gap between REF and NZ50 for 2030 primarily has an impact on the ability to reach the Canada-wide 2030 target, although it is difficult to see how this could be further accelerated from the CER baseline.

Emissions from transport evolve more or less similarly before 2030 in REF and NZ50, showing the high cost of substantially transforming the sector on the short term, especially in the absence of credible scalable solutions. This does not mean that further measures, in particular targeting heavy merchandise transport decarbonization or off-road transport, are not needed over the next few years, but rather that their impact would be felt later on. They are nevertheless necessary: after 2030, the gap between REF and NZ50 widens very rapidly. Agriculture is another sector that is difficult to transform over the short term.

Emissions from oil and gas production will not decrease to levels suggested by NZ50 without additional constraints.

The evolution of the oil and natural gas extraction and transformation sector differs markedly across scenarios. By 2030, the reference scenario shows a small reduction in emissions (-6%), although it is much smaller than in NZ50 (-29%). The gap is drastic over the rest of the horizon as NZ50 brings emissions down to only 10 $MtCO_2e$, while they bounce back to 2021 levels in REF.

In short, despite the fact that longer-term demand for oil on a global scale may be much lower than anticipated, depending on the pace of climate action abroad, options to decarbonize this sector on the very short term and truly initiate a net-zero pathway require strong policy measures to curtail emissions. Whether the cap on oil and gas emissions currently being developed by the federal government will be successfully implemented to help reach this goal is an important question. Another is what additional actions are needed to manage the phasing-out of a large part of the sector and minimize the impact on employment and export revenues. This remains an open question to which few solutions are currently being proposed.

Given the time left, realistic constraints on infrastructure deployment before 2030 make some NZ50 results very optimistic or even, in some cases, questionable in relation to the longer-term trajectory.

Since the 2030 check point is less than six years away, one question worth asking is whether including the 2030 target in net-zero scenarios may lead to transformations that are either very unlikely to be implemented on such a time scale or – even more fundamentally – associated with infrastructure that may become less necessary on the longer term.

As concerns the former possibility, the extent of technology switching in net-zero scenarios (notably toward heat pumps in buildings and electric vehicles) assumes that deployment can match the pace suggested by the results. However, this is not a given and careful estimations of the resources needed to implement these transformations are lacking at the moment and suggest that it is entirely possible that Canada will fall short even from REF projections, let alone those of NZ50.

Table 6.1 – Summary of GHG reductions across sectors

	2021	2030		2050	
	Reference year	REF	NZ50	REF	NZ50
Reductions wrt 2005 (730 $MtCO_2e$)	-6%	-14%	-40%	-25%	-100%
Total net emissions ($MtCO_2e$)	684	632	439	546	0
Sectors					
Electricity production	77	49	13	5	-17
Oil and gas (including fugitive emissions)	185	175	131	181	10
Buildings	72	54	37	36	3
Industry (outside of oil and gas)	92	89	64	99	18
Transport	167	169	166	106	29
Agriculture	58	64	58	70	49
Waste	18	9	7	7	5

The second point above, that is, that meeting the 2030 target leads to questionable infrastructure assumptions in some specific cases, is illustrated by the NZ50 result for syngas. While it is technically feasible to deploy syngas production to the levels suggested by the results, thereby providing a contribution to GHG reductions through the associated biochar output, it is unclear whether this option makes sense on the longer term. Most of this deployment helps achieve the 2030 target but then does not increase further, and once we approach 2050, the need for biochar is reduced as other negative emissions options become cost competitive. Thus, the inclusion of the syngas-biochar production in the modelling leads to more flexibility in meeting the 2030 target but the results suggest an infrastructure buildout that would be become less necessary on the longer term.

The implication of these observations is that interim targets matter. This is important to properly assess our results as the pace of transformations discussed in the last few chapters assumes that there are no interim targets between 2030 and 2050, which opens up the possibility to leave most transformations required by net-zero pathways until the 2040s. In practice however five-year targets will be established, as required by the Net-Zero Accountability Act, and for good reason. Pushing transformation down the road increases the risk of implementation difficulties and careful planning of the entire horizon to 2050 is certainly warranted.

However, the above makes one thing very clear: given the limited progress so far, it becomes increasingly expensive to realize transformations across sectors, to say nothing of implementation issues, in order to reach -40% by 2030, which is why the model chooses compensating emissions through biochar rather than deeper reductions.

6.1.3 Understanding the fundamental nature of this modelling effort

In the introductory chapter, we described the model used in this report and its specific characteristics, as well as how these features can influence the results, which must interpreted without losing track of these features. Before wrapping up the conclusion by providing overarching insights from the results presented in the previous chapters, it is important to put these fundamental aspects of the model in more concrete terms in order to understand how to look at the results and gain the best possible insights from them.

One point to note is that, given the cost optimization process, some technologies show a strong presence over a short time frame. This is the case for instance for syngas and biochar in the 2020s, light duty electric vehicles in the 2030s, wind power and nuclear SMR production in the 2040s, and hydrogen in the 2050s. In reality however uptake curves may be smoother, changing the pathway in various ways, including longer delays to reach the potential or increasing the need for early adoption at higher cost. In other words, results suppose that we can deploy infrastructure easily and at a very rapid pace. However, as we noted in the previous chapters, the many barriers to such deployment should lead to caution in assuming that it is possible.

Another issue deriving from optimization is that many transformations are assumed to realize their full potential, while this might not be the case in practice. One example is the large-scale electrification across sectors as electricity becomes the main supply of energy in the mix throughout the economy. While enabling this supply already requires very significant infrastructure buildout to produce, transport and distribute this additional electricity, the fact that the model operates through an optimization process implies that the needs for electricity infrastructure are likely to be understated.

Finally, while we take a fairly conservative position on the evolution of technologies, including their cost, some of them are not yet deployed at scale. There thus remains considerable uncertainty about the capacity of the supply chain, from natural resources to labour, to deploy these technologies at scale and cost.

With these caveats in mind, concluding a proper assessment of the results obtained in this exercise requires a careful balancing of the broader orientations suggested in net-zero scenarios with the uncertainty remaining, including that tied to the limitations of the model used. As we stated at the beginning of this report, no modelling can be a crystal ball: the value is in a deep comparative analysis of the pathways obtained, taking into account the assumptions and functioning of cost optimization.

6.2 Pathways to 2050: key insights from modelling Canada's transformation

Through a synthesis of the results from the scenarios modelled in this report, we are able to draw several important conclusions for this Outlook as a whole, highlighting a number of issues that are determinant for the transformation of Canada's energy system toward net zero.

Takeaway No. 1: Net-zero changes everything and the 2030 target must not hinder the long-term goal

Enabling a transformation pathway compatible with reaching net-zero emissions in 2050 has immediate implications. While intermediary targets are necessary, it must be kept in mind that the main objective of setting and aiming for interim targets is to ensure sufficient progress in the long run, that is, to reach net-zero by 2050. The implication is that all short-term choices made to reduce greenhouse gas emissions, or even to develop new industrial sectors, have to be compatible with reaching net zero.

There are two important ways in which this is illustrated in our results. First, there are very few so-called transition fuels or technologies on the 2050 time horizon. In order to minimize costs and implementation challenges on the road to 2050, all choices must be compatible with 2050, even when short-term gains could seem more helpful to reach the 2030 target. For instance, moving from diesel to natural gas in trucking is not a transformation compatible with net zero, and any remaining role for natural gas in buildings must be phased out as soon as possible. Otherwise, the additional investments required after 2030 to roll back short-term actions incompatible with net zero in 2050 will add to the already daunting task of realizing a net-zero pathway.

Second, while the stringency of intermediary targets like those of 2030 may be a necessary motivator and reference to trigger action on the very short term, forcing it as a hard constraint in the net-zero scenario leads to technological solutions that are not currently used. In particular, the negative emissions obtained from syngas and biochar production result in an important buildout of this capacity, and are partially retired after 2050. Beyond unsettled GHG accounting debates, which may lead to a different accounting of this contribution, it would be wise to plan this buildout carefully to avoid the potential disadvantages of infrastructure lock-in on the longer-term.

Takeaway No. 2: Even though some recent policies are an important step in the right direction, more is needed, in particular from the provinces

Current policies take a significant step in initiating transformations compatible with reaching net zero. The carbon price increase schedule, the Clean Electricity Regulations, and the Zero Emissions Vehicles mandate are important examples, as they contribute to reversing the growth trend in emissions noted in the recent past. However, as the results over the past few chapters indicate, the measures in place are far from sufficient to reach either the 2030 reduction target or net-zero emissions by 2050.

Some sectors require urgent attention as the REF scenario shows almost no change in their mix, while NZ50 completely transforms them to meet the net-zero target: this is the case across most industry sub-sectors for instance, as well as in heavy-duty transport. While some discussions are certainly ongoing in these areas, we should point out that certain sectors remain understudied despite their playing a large role in remaining emissions even in NZ50. Off-road transport is one such sector, where diffuse technologies and vehicles have made it more difficult to approach but where reductions could be realized at relatively low cost.

One aspect to highlight as well is that most of the progress made in implementing transformative measures has come from the federal level. In some provinces, action is lacking, completely ignoring the need for detailed provincial roadmaps to net zero; in others, targets and plans to reduce emissions are ambitious on paper, but meaningful strategies and actions are rare, and when they do exist, there are few mechanisms to ensure the measurement of their concrete impact on emissions.

The national cost optimization approach used in our modelling shows that there is considerable room for nationwide federal government programs to help tackle common challenges. Nevertheless, all provinces must make choices about how they want to contribute to the national effort to reach net zero that take into account their specific situation and rapidly translate these choices into concrete measures.

Takeaway No. 3: Building the backbone of the energy system needed to enable net zero by 2050 requires rapidly planning and realizing massive infrastructure transformations.

Our results assume significant energy savings from a future system with much higher energy productivity. Nevertheless, despite including all energy efficiency measures that are economically viable, the new needs for energy production, transport and distribution infrastructure are vast. The results are also likely to undershoot the true needs, as the optimization nature of the model assumes little overhead costs in the transformations. In any case, building significant additional capacity across this system or upgrading existing distribution networks takes time. Nevertheless, the transformations in the delivery of energy services required by net-zero pathways can only be enabled if this energy supply is available in time.

The direct implication is that urgent planning and implementation of the strategies to build this system are needed to ensure that infrastructure deployment challenges do not end up slowing down or impeding transformations. As Box 2.2 shows, the list of challenges that could delay or even prevent some of this deployment is long, one more reason to ensure that we get a head start.

Takeaway No. 4: The dramatic expansion of electricity's role in the mix is not simply a challenge in terms of infrastructure construction since it requires a complete rethinking of how to support an economy mainly with electricity as opposed to the traditional energy mix used in the past.

It is difficult to understate the role of electricity in net-zero pathways. Populations will have to make future choices about the relative importance of the technological options to favour, but while electrification provides cost-effective solutions to decarbonize a broad variety of energy services, the dramatic expansion of this source comes with challenges that extend well beyond the infrastructure deployment issues underlined in point No. 3 above.

Some of these issues are technical. For example, the implementation of solutions to prevent or limit the exacerbation of peak electricity demand or the upgrades to local distribution networks to enable larger power needs created by newly electrified services are substantial and complex but ultimately limited to technological options. However, the changes that come with a much greater need for resilient networks may be underappreciated as more people become reliant on electricity for more services, including the most essential ones. What's more, industrial development will need to be planned in conjunction with network deployment, creating additional constraints as to the choice of industries, sitings and the participation of private electricity producers. In the end, it is very likely that this supply will be much less flexible for development purposes as the greater power demand associated with new industrial production will need to be provided with a limited set of few low-carbon alternatives.

Takeaway No. 5: Additional measures are needed for the transport sector

Transport services are an area where subsector specificities require tailored measures for effective decarbonization. As our results show, the ZEV mandate, if implemented fully to 2035, will make personal vehicles close to zero emissions before 2050. This is an improvement that comes much closer to matching the needs indicated by the NZ50 scenario results, even though the continued growth of the passenger vehicle fleet should be addressed sooner rather than later with more structuring measures – through more developed and effective public transit or car-sharing systems, notably – to decrease the pressure on transport networks. Nevertheless, such measures are completely lacking for all other subsectors of transport and decarbonization is projected to be minimal as a result.

Given these findings, it is clear that strong measures must be implemented to decarbonize heavy (road and marine) and off-road transport, the latter of which remains understudied despite accounting for 40% of remaining emissions for the sector in 2050 in net-zero scenarios. It should be noted that two options are not covered in the scenarios we developed: intermodal shifts for merchandise transport and combinations of technologies, like catenary for long distance coupled with small-range battery vehicles. In both cases, the potential contribution to the challenge of decarbonizing merchandise transport is quite significant.

Takeaway No. 6: Transformations in industry require specific roadmaps, including for process emissions

Industry as a whole (outside of oil and gas production) brings emissions from energy combustion into negative territory in net-zero scenarios. However, the opportunities differ significantly according to subsectors and, in any case, industrial process emissions only decrease by 46% in NZ50. Low-carbon solutions for industrial processes are currently limited and preclude further reductions unless demand for the production declines to much lower levels than current projections. This points to the need for developing decarbonization roadmaps for key subsectors, with a special focus on industrial processes.

Takeaway No. 7: Assessing the role of biomass in decarbonization pathways, including beyond bioenergy, is necessary

The question of determining the specific role of biomass resources in net-zero pathways is a complicated one. While some bioenergy applications provide interesting avenues like negative emissions from hydrogen production, as well as contributions in replacing fossil fuels in hard-to-abate applications, all of these depend on a complex web of considerations. These include the accounting for emissions from land use and forestry as well as various biomass applications outside of the energy sector, notably as a replacement of other structural materials in construction.

The question of the role of biomass in net-zero pathways may be framed as a reflection on what types of problems it can help solve. Is it providing negative emissions applications necessary to obtain final energy while compensating remaining emissions from agriculture or industrial processes? Is it through wood pellets burned in some types of buildings during peak demand to alleviate electricity demand? Is it through renewable natural gas used in heavy industries? Answering these questions will require the availability of much better data to map out the different resources and activities linked to biomass and to enable comparative analyses of the options and realistic potential of its contribution to net-zero pathways.

Takeaway No. 8: Exploring and planning the deployment of negative emissions options is urgent

Various negative emissions technologies are included in the vast technological catalogue used by NATEM, including BECCS hydrogen gasification, electricity production and industrial heat production, direct air capture, and biochar production. While the technology readiness level of these options may not be uniform, they all share one thing: none of them are currently deployed at any significant scale. The implication is that for the levels of negative emissions in NZ50 to be achieved by 2050, a capacity of between -4 and -7 $MtCO_2e$, whatever the exact mix of technologies, would need to be installed every year from now to 2050. Therefore, it is premature to assume that this potential could be realized in this time frame.

Part of this uncertainty must be remedied by gaining more experience with any or all negative emissions technologies to establish a more realistic assessment of their potential, through both pilot projects and certain commercial-scale attempts. However, the questions about this contribution cannot be limited to technological and cost-related issues. A consensus should be reached in the near future on how to clarify the GHG accounting of biomass resources involved and how to manage the biomass resources used should be planned in detail in order to ensure that their natural capture process is renewed optimally and that the impact on biodiversity is understood and minimized.

At the same time, to increase the likelihood of Canada reaching net zero, it is necessary to double down on the development of low-carbon solutions for hard-to-decarbonize sectors in order to reduce to the minimum the amount of CO_2 that needs to be captured and sequestered. This need is evidenced by the fact that current edition of the CEO projects negative emission needs at a level similar to those of CEO 2021.

Takeaway No. 9: While modelling does not answer every question about the future, it does however provide guidance on how to think about choices that must be made today to make it possible to attain net zero

Modelling results closely depend on the conservative hypotheses that we have adopted about the evolution of technologies, the barriers to investments and the overall costs of the transformation. This means that the specific evolution in the understanding of agriculture and nature-based solutions, as well as of technologies under intense development such as hydrogen, small nuclear reactors, large scale energy storage, many industrial processes, and heavy transport, is still uncertain and even unknown. Their future is dependent not only on further research and technological progress, but also on political orientations and choices that will lock in some of the infrastructure-heavy solutions (such as catenary or hydrogen-powered trucks) early-on and, by doing so, reduce the number of possible futures to consider (Meadowcroft *et al.* 2019 and 2021).

Taking these uncertainties into account should not obscure the extent of the transformations of the Canadian economy in net-zero scenarios in terms of energy production. The dramatic reductions in oil and gas production over just one or two decades, to state the most consequent example, represents a transformation that has nationwide implications – just like the failure to complete them in the attempt to reach net zero. What the net-zero Canadian economy would actually look like remains misunderstood. Considerable attention from all political and economic actors and from citizens across the country is necessary to expand this understanding.

For this reason, the third part of the CEO, to be published over coming months, will provide deeper insights into some of these questions.

6.3 References

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A

Main modelling hypotheses

This Appendix gives an overview of the main hypothesis used by NATEM for this Outlook.

Main macroeconomic hypotheses

Table A.1 – Real GDP

	2021 $2012 Millions	2030 $2012 Millions	2040 $2012 Millions	2050 $2012 Millions
CAN	$2,090,196	$2,498,101	$2,928,382	$3,330,174
AB	$335,864	$406,178	$463,424	$527,987
BC	$282,193	$353,740	$444,094	$522,369
MB	$65,926	$75,889	$87,486	$96,052
NB	$34,493	$38,450	$41,925	$44,469
NL	$32,706	$39,353	$34,206	$31,132
NS	$43,008	$49,895	$55,586	$59,519
NT	$4,414	$5,008	$5,170	$5,482
NU	$3,396	$3,472	$4,263	$5,286
ON	$794,680	$949,633	$1,120,766	$1,282,248
PE	$6,886	$8,238	$9,754	$11,304
QC	$409,473	$473,051	$551,390	$622,489
SK	$82,302	$101,041	$117,757	$130,279
YT	$3,035	$3,929	$4,020	$4,591

Source: CER - Canadian Energy Regulator (2021). Canada's Energy Future 2021: Energy Supply and Demand Projections to 2050. Macro Indicators. https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

Main macroeconomic hypotheses

Table A.2 – Demography

	2020 Persons	2030 Persons	2040 Persons	2050 Persons	2060 Persons
CAN	38,226,498	42,840,800	46,724,200	50,090,800	53,463,400
AB	4,443,773	5,254,600	6,212,900		
BC	5,202,378	6,027,500	6,541,200		
MB	1,391,979	1,527,900	1,686,700		
NB	790,398	837,700	854,700		
NL	520,452	510,100	486,300		
NS	991,117	1,079,200	1,097,600		
NT	45,597	48,600	50,100		
NU	39,711	43,000	47,700		
ON	14,809,257	16,883,800	18,615,400		
PE	164,758	187,700	204,400		
QC	8,602,335	9,080,500	9,396,500		
SK	1,181,493	1,311,100	1,479,800		
YT	43,250	48,900	50,900		

Source: Statistics Canada (2022). Projected population, by projection scenario, age and sex, as of July 1. https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1710005701

Main energy prices used for energy commodities imported/exported from/to Canada

Table A.3 – CER's "Reference" scenario

Canada		2021	2030	2040	2050
Brent	2022 US$/bbl	$75.85	$75.00	$75.00	$75.00
West Texas Intermediate (WTI)	2022 US$/bbl	$72.98	$72.50	$72.50	$72.50
Western Canadian Select (WCS)	2022 US$/bbl	$58.83	$60.00	$60.00	$60.00
Canadian Light Sweet (CLS)	2022 US$/bbl	$85.93	$88.90	$90.30	$89.60
Henry Hub	2022 US$/MMBtu	$4.18	$3.75	$4.08	$4.40
Nova Inventory Transfer (NIT)	2022 US$/MMBtu	$3.12	$3.00	$3.34	$3.66

Source: CER - Canadian Energy Regulator (2023). Canada's Energy Future 2023: Energy Supply and Demand Projections to 2050, Benchmark Prices. https://apps.rec-cer.gc.ca/ftrppndc/dflt.aspx

Table A.4 – CER's "Global net-zero" scenario

Canada		2021	2030	2040	2050
Brent	2022 US$/bbl	$75.85	$35.00	$29.50	$24.00
West Texas Intermediate (WTI)	2022 US$/bbl	$72.98	$32.50	$27.00	$21.50
Western Canadian Select (WCS)	2022 US$/bbl	$58.83	$20.00	$17.00	$11.50
Canadian Light Sweet (CLS)	2022 US$/bbl	$85.93	$59.00	$57.00	$55.00
Henry Hub	2022 US$/MMBtu	$4.18	$2.00	$1.90	$1.80
Nova Inventory Transfer (NIT)	2022 US$/MMBtu	$3.12	$1.70	$1.60	$1.50

Source: CER - Canadian Energy Regulator (2023). Canada's Energy Future 2023: Energy Supply and Demand Projections to 2050, Benchmark Prices. https://apps.rec-cer.gc.ca/ftrppndc/dflt.aspx

Oil, gas and coal production profiles

Table A.5 – Crude oil production (upper bound from CER Reference scenario)

Canada		2021	2030	2040	2050
Total	k bbl/d	6,076	7,512	7,673	7,437
Conventional Light	k bbl/d	669	1,105	1,172	1,080
Conventional Heavy	k bbl/d	520	569	592	569
C5+	k bbl/d	138	192	198	203
Field Condensate	k bbl/d	357	687	777	816
Mined Bitumen	k bbl/d	1,592	1,662	1,619	1,619
In Situ Bitumen	k bbl/d	1,656	2,071	2,139	1,973
(Upgraded Bitumen)	k bbl/d	1,145	1,226	1,177	1,177

Source: CER - Canadian Energy Regulator (2023). Canada's Energy Future 2023: Energy Supply and Demand Projections to 2050, Oil production. https://apps.rec-cer.gc.ca/ftrppndc/dflt.aspx

Table A.6 – Crude oil production (lower bound from CER Global net-zero scenario)

Canada		2021	2030	2040	2050
Total	k bbl/d	6,076	6,797	3,599	1,596
Conventional Light	k bbl/d	669	860	556	330
Conventional Heavy	k bbl/d	520	471	266	138
C5+	k bbl/d	138	170	125	94
Field Condensate	k bbl/d	357	588	402	260
Mined Bitumen	k bbl/d	1,592	1,622	776	344
In Situ Bitumen	k bbl/d	1,656	1,882	741	118
(Upgraded Bitumen)	k bbl/d	1,145	1,204	732	312

Source: CER - Canadian Energy Regulator (2023). Canada's Energy Future 2023: Energy Supply and Demand Projections to 2050, Oil production. https://apps.rec-cer.gc.ca/ftrppndc/dflt.aspx

Table A.7 – Natural gas production

Canada		2021	2030	2040	2050
Total	G ft3 / d	16.12	14.25	9.70	5.52

Source: CER - Canadian Energy Regulator (2023). Canada's Energy Future 2023: Energy Supply and Demand Projections to 2050, Oil production. https://apps.rec-cer.gc.ca/ftrppndc/dflt.aspx

Carbon Capture and Storage (CCS) costs

Table A.8 – Investment costs

	2030	2050
DAC ($2022/t)		
Solid sorbent	136	56
Liquid sorbent	134	106
CCS (CAPEX increase from standard tech		
Cement - MDEA	6 to 8	6 to 8
Cement - Amine with plasma torches	2.5	2.5
Cement - Calcium looping	3 to 4	3 to 4
Cement - Oxy-fuel calcination	3 to 4	3 to 4
Cement - Carbon capture with membrane	3 to 4	3 to 4
Lime - Capture	1.3 to 2	1.3 to 2
Iron & Steel - Capture	1.5 to 2	1.5 to 2
Chemicals - Capture	1.3 to 2	1.3 to 2
Pulp & paper - Capture	1.2 to 2	1.2 to 2

Electricity-related costs

Table A.9 – Electricity costs

	Investment costs (2022$/kW)			Fixed operation and maintenance cost
	2022	2030	2050	
Hydro				
Dam	$6,238	$6,093	$5,730	$57
Run-of-river	$4,175	$4,175	$4,175	$109
Nuclear				
Conventional	$6,550	$6,284	$6,037	$109
Small modular reactor - optimistic	$9,356	$8,911	$7,129	$10
Small modular reactor - pessimistic	$9,356	$9,356	$9,356	$10
Natural gas				
Standard	$1,325	$1,248	$1,102	$29
With CCS	$2,583	$2,583	$2,583	$9
Coal				
Standard	$4,077	$3,889	$3,610	$47
With CCS	$5,735	$5,500	$4,947	$80
Geothermal				
Hydrothermal	$5,269	$5,037	$4,556	$169
Enhanced geothermal systems	$25,453	$24,331	$22,010	$519
Biomass				
Standard	$4,178	$3,957	$3,614	$58
With CCS	$5,787	$5,385	$4,702	$122

Electricity-related costs

Wind				
Onshore	$2,219	$1,910	$1,525	$53
Offshore	$5,642	$5,584	$4,543	$111
Decentralized	$3,569	$3,569	$3,569	$137
Solar				
PV 1 axis	$1,544	$1,229	$1,045	$41
PV 2 axis	$2,017	$1,595	$1,349	$54
Concentrating solar	$7,147	$5,062	$4,094	$70
Rooftop PV	$1,727	$1,279	$1,028	$19
Other renewable				
Ocean thermal	$29,161	$29,161	$29,161	$883
Tidal	$6,052	$3,668	$3,668	$121
Wave	$9,170	$5,135	$5,135	$-
Biogas	$1,654	$1,473	$1,147	$21
Hydrogen fuel cell	$4,172	$4,172	$4,172	$42
Storage				
Battery utility scale 4h	$2,405	$1,247	$806	$11
Battery utility scale 8h	$4,656	$3,347	$2,289	$10
Battery decentralized	$962	$639	$436	$14
Pumped hydro - peak	$3,372	$3,372	$3,372	$8
Pumped hydro - seasonal	$168,607	$168,607	$168,607	$8
Compressed air - peak	$1,184	$1,184	$1,184	$15
Compressed air - seasonal	$59,212	$59,212	$59,212	$15

Hydrogen costs

Table A.10 – Production costs

	Investment costs (2022$/kW)			Fixed operation and maintenance cost
	2022	2030	2050	
Technology				
Steam methane reforming without CCS	$475	$475	$475	$23
Steam methane reforming with CCS	$1,104	$973	$755	$41
Autothermal reforming with CCS	$1,062	$956	$726	$40
Coal gasification with CCS	$5,140	$4,700	$4,430	$150
Biomass gasification without CCS	$1,073	$1,047	$1,020	$65
Biomass gasification with CCS	$3,100	$2,826	$2,501	$170
Electrolyzers	$1,194	$781	$562	$25

Table A.11 – Hydrogen transmission

	Investment costs (2022$/kW)			Fixed operation and maintenance cost
	2022	2030	2050	
Pipeline	$11	$11	$11	$0

Table A.12 – Hydrogen distribution

	Investment costs (2022$/kW)			Fixed operation and maintenance cost
	2022	2030	2050	
Truck	$16	$16	$16	$1
Ship	$5	$5	$5	$0
Refuelling station	$37	$37	$37	$2

Hydrogen costs

Table A.13 – Hydrogen storage

	Investment costs (2022$/kW)			Fixed operation and maintenance cost
	2022	2030	2050	
Salt cavern	$315	$315	$315	$92
Tank	$805	$805	$805	$32

Table A.14 – Synthetic fuels from hydrogen

	Investment costs (2022$/kW)			Fixed operation and maintenance cost
	2022	2030	2050	
Methanation	$910	$796	$609	$21
Fischer-Tropsch reactor - Jet fuel	$1,035	$889	$609	$21
Fischer-Tropsch reactor - Methanol	$1,035	$889	$609	$21

Table A.15 – Hydrogen consumption

	Investment costs (2022$/kW)			Fixed operation and maintenance cost
	2022	2030	2050	
Chemicals, manufacturing & pulp and paper - Industrial boilers (2022$/kW)	$146	$146	$146	$12
Iron & steel - Hydrogen direct iron reduction (k2022$/kt)	$499	$499	$499	$131
Cement - Plasma torches + hydrogen (k2022$/kt)	$30	$30	$30	$0

Policies

Table A.16 – Policies included in all scenarios

Jurisdiction	Policy Item
Federal	Federal Fuel Charge under Greenhouse Gas Pollution Pricing Act
	Federal Output-based Performance Standard
	Clean Fuel Regulations
	Incentives for LDZEVs and Zero-emission vehicle infrastructure program
	Incentives for MDZEVs and HDZEVs
	Clean Technology Investment Tax Credit Implementation note: – Tax credit of 30% for renewable electricity generation, stationary electricity storage, active solar heating equipment, heat-pumps, CSP, SMRs, non-road ZEV vehicles, charging stations, geothermal heat recovery
	Investment Tax Credit for Clean Hydrogen Implementation note: – 40% for a CI of less than 0.75 $kgCO_2e/kg\ H_2$ (applied for electrolyzers and ATR with CCS) – 25% for a CI greater than or equal to 0.75 kg, but less than 2 $kgCO_2e/kg\ H_2$; – 15% for a CI greater than or equal to 2 kg, but less than 4 $kgCO_2e/kgH_2$
	Investment Tax Credit for CCUS Implementation notes: – Tax credit of 37.5 - 60% for DAC and CCUS projects, including 60% for DAC in 2022 dropped to 30% in 2030. 40% in 2022, 50% in 2030, 25% after 2030 for biomass gasification with CCS for H2 production. 40% in 2022, 50% in 2030, 25% after 2030 for electricity generating plants with CCS. 40% in 2022, 50% in 2030, 25% after 2030 for all other CCS technologies
	Investment Tax Credit for Clean Electricity Implementation notes: – Tax credit added for large hydro and nuclear plants. Other technologies are covered by the Clean Technology tax credit.
	Federal Methane Goals from 2018
	HFC Regulation (Kigali amendment)

Policies

Federal	Heat pump grants / funding
	Greener Homes Grant
	GHG emissions standards for vehicles through 2027 (CAFE)
Ontario	Emissions Performance Standard
	Cleaner Transportation Fuels Regulation
	Landfill Gas Regulation (O. Reg. 216/08 and 217/08)
	Strategy for a Waste-Free Ontario
	Nuclear Refurbishment Implementation notes: – Included based on IESO 2022 annual planning outlook.
	Ontario and Canadian government investments in phasing out coal use at Algoma's and ArcelorMittal Dofasco's steel facilities Implementation notes: – Included based on company announcements
	Electricity supply procurements Implementation notes: – 1 SMR, in service by 2028 – 300 MW; – 1,500 MW new natural gas – all in by 2027, starting to come online in 2026; and – 2,500 MW 4-hr Li battery storage – all in by 2027, starting to come online in 2026.
	Off-shore wind moratorium
	Electricity pricing policies: Comprehensive Electricity Plan (CEP) and the Ontario Electricity Rebate (OER)
	Industry conservation initiative Implementation notes: – Modelled as a smart technology that act as a storage of electricity, it charges off-peak and discharge during peak. This way the electricity production is displaced off-peak, but our industry load curve remains the same. There is a revenue (for industry) when displacement from peak to off-peak happens. Displacement values are similar to what IESO provide from 2024 to 2040.
	Framework for regulating geologic carbon storage (CCS)

Policies

British Columbia	Zero-emissions vehicle mandate and incentives
	CleanBC Better Homes and Better Buildings programs
	CleanBC Industrial Electrification
	Renewable Fuel Regulation
	Low Carbon Fuel Standard
	Renewable Natural Gas Regulation
Quebec	Quebec cap and trade Implementation notes: – Modelled as a carbon price with some free allocations - the price reflects the idea that trade will happen with California so cap is not binding in QC.
	Roulez vert program
	Zero-emissions vehicle standard
	Renewable Natural Gas Mandate
	Chauffez vert program

Policies not yet implemented but included in the modeling

Clean Electricity Regulations

- Starting 2035, coal and petroleum coke units can no longer operate.
- Starting in 2035, for new oil fueled units can operate up to 450 h/y.
- For existing oil fueled units: for units commissioned before 2025, starting the later of 2035 or 20 years after commissioning, they can operate up to 450 h/y and emit less than 150 $ktCO_2/y$.
- For new natural gas units : starting 2035 they can operate using 100% RNG with no restriction. Fossil natural gas is allowed for a maximum of 450h/y (5%), the rest of the time the unit can use RNG. No use of H_2 blend is considered.
- For existing units of natural gas : starting 2035 or 20 years after commissioning they can operate using 100 % RNG with no restriction. Fossil natural gas is allowed for a maximum of 450h/y (5%), the rest of the time the unit can use RNG. They can emit a maximum of 150 $ktCO_2/y$. No use of H_2 blend is considered.
- Natural gas units with CCS technology are assumed to meet regulatory constraints and can operate without limits.
- After 2035 all electricity units are subject to the full carbon price, i.e. the Emissions Performance Standards is assumed to apply with a threshold of 0 starting 2035 as opposed to 310 tCO_2e/GWh in the reference case.
- We assume Nunavut, Northwest territories and Yukon to be excluded from this policy
- Existing electricity units are modelled individually.
- Existing remote communities units are excluded from the regulations.

Zero-Emission Vehicles sales mandate

- 2030: 60% of light-duty vehicles sold must be zero-emission
- 2035: 100% of light-duty vehicles sold must be zero-emission