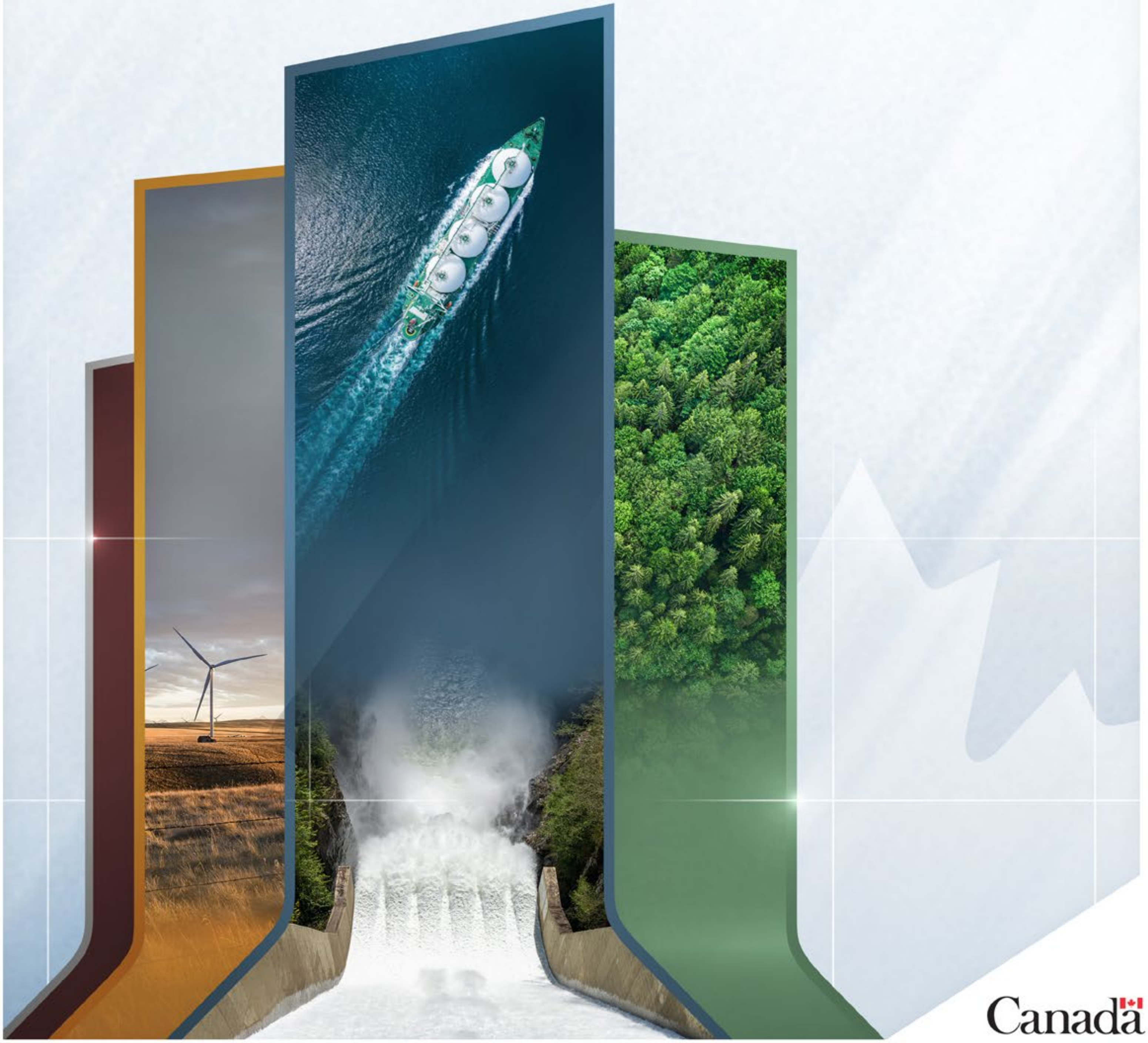
Canada Energy Regulator
Régie de l'énergie du Canada

Canada's Energy Future 2026

Energy Supply and Demand Projections to 2050



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Letter from the CEO

I am pleased to introduce the 2026 edition of Canada's Energy Future. Like its predecessors, this report explores how Canada's energy system could evolve over the long term. It also reflects the unique challenges and opportunities of today's world, where rapid technological change, shifting global political and economic dynamics, and heightened uncertainty is reshaping the context in which Canadians live and work.

The value of a long-term outlook lies in its ability to cut through short-term noise and provide a structured way to think about the future. This report builds on past editions, while also evolving in response to feedback and changes in the energy landscape. This includes deeper analysis of energy security and trade diversification, an expanded look at Indigenous perspectives on the energy transition, and new insights on emerging drivers such as the growing electricity needs of data centres.

Our team also considered how best to reflect the major uncertainties shaping Canada's energy future, from shifting trade patterns to volatile global policy and changing economic conditions. This report explores a broad range of potential outcomes including by capturing the effect of both higher and lower economic growth and prices. We also continue to examine one possible pathway for Canada to achieve net-zero emissions by 2050. Together, this range of futures provides a way to test assumptions, understand how different forces could shape Canada's energy system, and support evidence-based dialogue. No single outlook can capture every possibility; the value lies in comparing scenarios to see how different assumptions change the picture and what commonalities emerge.

As always, Canada's Energy Future is not a forecast or prediction of the future. It does not recommend a particular course of action. The various modeled scenarios are based on different assumptions, and these assumptions should not be interpreted as policy preferences or recommendations. Instead, it provides a transparent platform to inform Canadians about the possible paths ahead and serves as a foundation for broader dialogue and further analysis, helping diverse audiences explore the implications and opportunities within Canada's evolving energy landscape.

I want to thank everyone who shared their insights with us throughout the development of this report. This includes experts from across the energy system, government and industry representatives. It also includes Indigenous Peoples engaged through our collaboration with Mokwateh, whose input enabled us to provide a section in this report about Indigenous perspectives on the future of energy in Canada. All of your perspectives helped inform our assumptions, improve our analysis, and strengthen this report. I also want to recognize the dedication and expertise of the Canada Energy Regulator team, whose work and commitment made this report possible.

Sincerely,
Tracy Sletto
Chief Executive Officer
Canada Energy Regulator

Executive Summary

Overview

Canada's Energy Future 2026: Energy Supply and Demand Projections to 2050 is the latest long-term energy outlook from the Canada Energy Regulator (CER). The Canada's Energy Future series explores how possible energy futures might unfold for Canadians over the long term, building on decades of economic and energy modelling and analysis. Our scenarios cover all energy commodities and all Canadian provinces and territories.

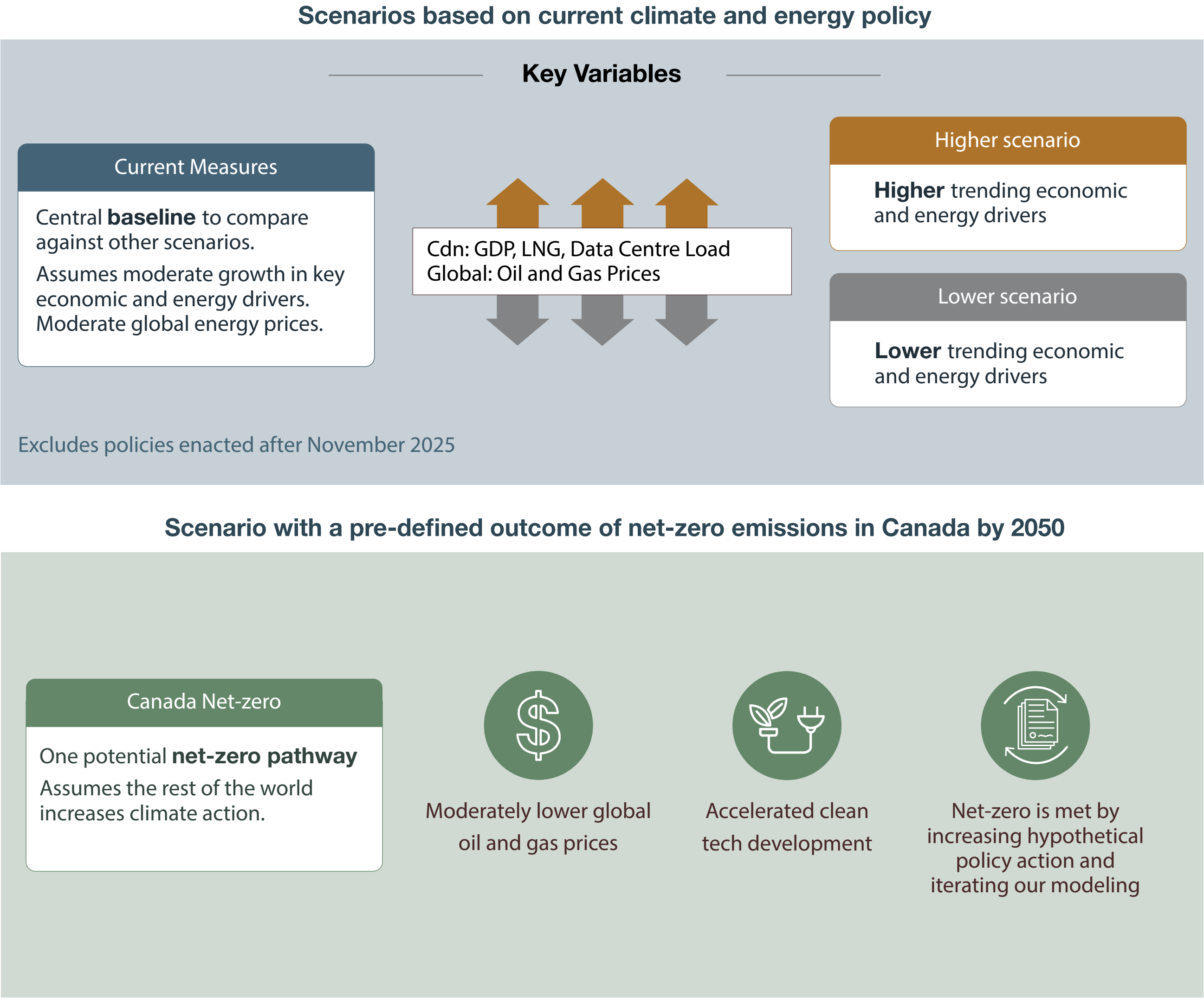
This scenario analysis explores future uncertainties facing the energy system. Relying on just one scenario to understand the energy outlook implies too much certainty about what could happen in the future. **The results in this report are not predictions about the future nor policy recommendations. Rather, they are the product of modeled scenarios based on a specific set of assumptions—and these assumptions are outlined transparently in the report or its appendices**.

This report includes four scenarios to explore Canada's energy outlook. One of these is Current Measures, a traditional baseline scenario. To explore uncertainty in energy and economic drivers, we introduce two new symmetrical scenarios that bracket the Current Measures scenario: the Higher scenario and Lower scenario. These scenarios examine outcomes if key drivers of Canada's energy system—specifically, Canadian gross domestic product (GDP) growth, liquefied natural gas (LNG) exports, data centre electricity demand, and global oil and natural gas prices—trend higher or lower than in Current Measures. Together, they define a range of outcomes driven by factors not directly tied to a specific future goal or policy outcome. We do not assign probabilities to any of our scenarios.

We also updated the Canada Net-zero scenario, first introduced in Canada's Energy Future 2023. Compared to the first three scenarios, which do not have a pre-determined end point, the Canada Net-zero scenario begins with a predetermined end point of net-zero greenhouse gas (GHG) emissions for Canada by 2050—exploring what a pathway to that end point could look like. It assumes the rest of the world also increases the pace of climate action, leading to lower global oil and natural gas demand than Current Measures (hence lower oil and natural gas prices) and lower clean technology costs, due to increasing technological development in Canada and abroad.

To explore key issues related to energy security and trade diversification, the report includes a section that examines what the projections imply for three aspects of Canada's energy system: the energy self-sufficiency of Central Canada (with a focus on Ontario and Quebec, given their reliance on energy arriving from the U.S.), the resiliency of the supply chain needed to expand Canada's electricity system, and the potential for diversifying western Canada's crude oil exports.

Figure ES.1: Illustration of the scenarios in Canada's Energy Future 2026



Scenarios based on current climate and energy policy

Key Variables

Current Measures

Central **baseline** to compare against other scenarios.

Assumes moderate growth in key economic and energy drivers. Moderate global energy prices.

Cdn: GDP, LNG, Data Centre Load
Global: Oil and Gas Prices

Higher scenario

Higher trending economic and energy drivers

Lower scenario

Lower trending economic and energy drivers

Excludes policies enacted after November 2025

Scenario with a pre-defined outcome of net-zero emissions in Canada by 2050

Canada Net-zero

One potential **net-zero pathway**

Assumes the rest of the world increases climate action.

Moderately lower global oil and gas prices

Accelerated clean tech development

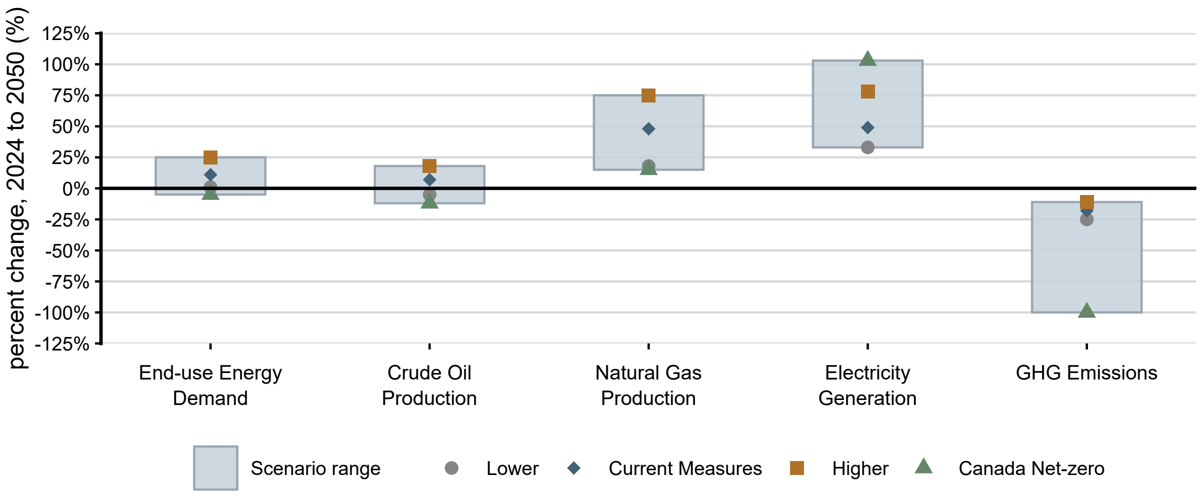
Net-zero is met by increasing hypothetical policy action and iterating our modeling

Summary: Key Results and Uncertainties

Key Results

Our scenarios provide a range of outcomes for Canadian energy supply, demand, and GHG emissions, some of which are shown in Figure ES.2. Overall, our scenarios show that the assumptions we change across the scenarios—such as economic growth, energy prices, and level of climate action—have an impact on future energy system trends.

Figure ES.2: Percentage change in energy demand, oil and natural gas production, electricity generation, and GHG emissions, 2024 to 2050, by scenario



Key Uncertainties

In some cases, there are wide projected ranges shown in Figure ES.2. The future is uncertain, and the ranges are not intended to capture every possibility. It is plausible that actual trends could be outside these ranges. Some important societal or economic trends that are not included in our modelling could further influence Canada's energy future, including:

- Further geopolitical change and trade policy
- Domestic and international technology development and deployment
- Changes to investment related to increased Indigenous involvement in projects, including partnerships and equity ownership in energy projects
- Global dynamics in oil and natural gas supply
- Global supply chains
- Investor sentiment for major projects

Key Findings

1 Electricity plays an increasingly important role in Canada’s energy system across all scenarios.

By 2050, Canada’s total energy use varies widely across scenarios—from 5% below today’s levels to 25% above. Electricity demand grows substantially in every case, while hydrocarbon use remains relatively stable except in the Canada Net Zero scenario, where it drops by 40%.

Canada’s end-use demand grows by 11% from 2023 to 2050 in Current Measures, whereas the Higher and Lower scenarios have around 10% more or less demand than Current Measures in 2050 (Figure ES.3). In Canada Net-zero, end-use demand is 5% lower than 2023 in 2050. Electricity demand[1] grows significantly in all scenarios, ranging between a 26% to 85% increase from 2023 to 2050, and growth comes from a wide variety of end-uses. All scenarios include increasing adoption of passenger electric vehicles (EVs) (in part due to all scenarios including the federal standard that requires 100% of vehicle sales in 2035 to be zero-emission vehicles[2]), and demand from new data centres. The additional electricity demand in the Higher scenario is driven by assumptions related to greater data centre load growth, and higher assumed economic growth. In the Current Measures, Higher, and Lower scenarios, fossil fuel demand is relatively stable, with the share being used for non-combustion purposes, like petrochemical feedstocks, lubricants, and asphalt rising from 15% currently, to 20-25% by 2050.

Canada Net-zero sees the most change in Canadian energy demand. Electricity demand is highest among the four scenarios, reflecting greater electrification across the economy. By 2050, electricity is the largest energy type in the mix, accounting for nearly 35% of total demand, compared to 23% in Current Measures and 18% today. Fossil fuel demand declines by 40% but still plays a relatively large role. By 2050, about one-third of fossil fuel demand is for non-combustion purposes, given steeply falling use of combusted fossil fuels.

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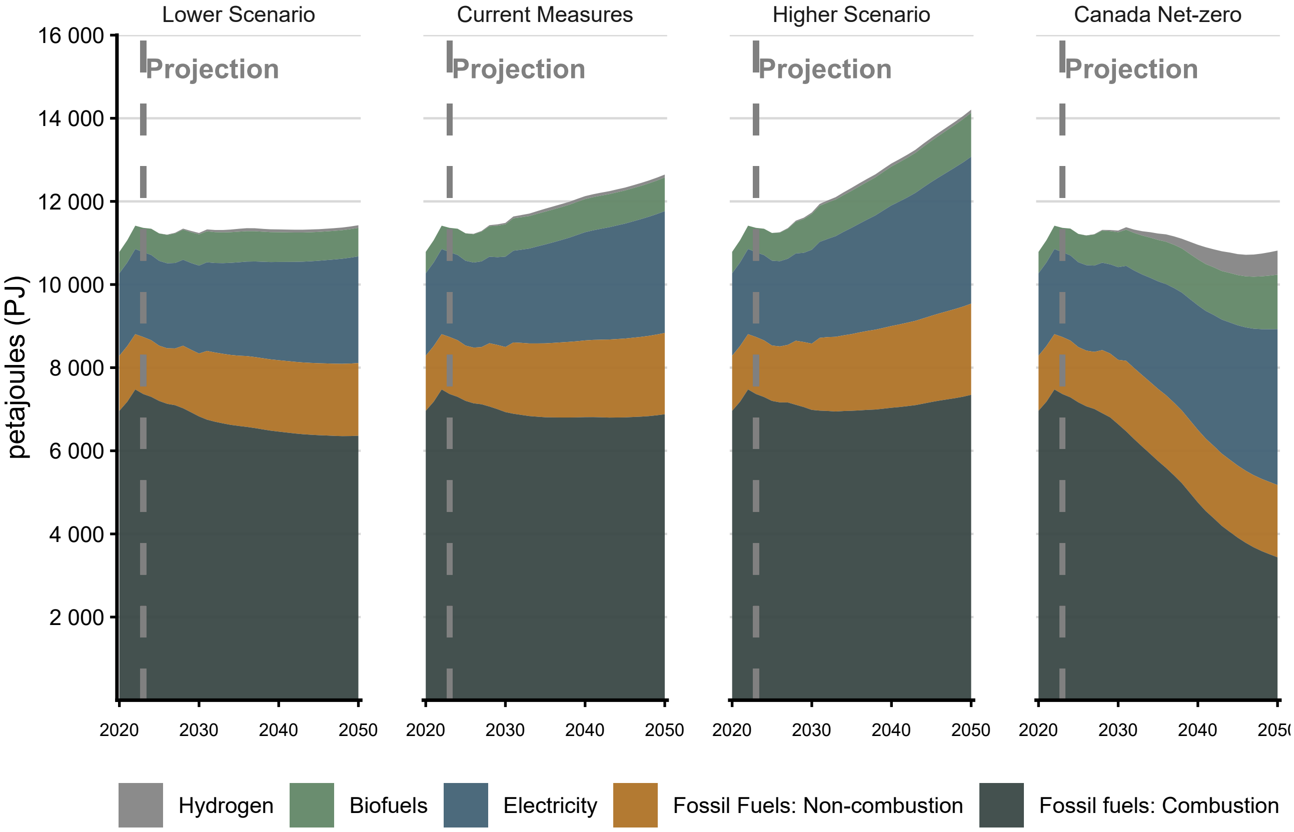
[1] Unless otherwise stated, references to energy, electricity, and fuel demand refer to end-use demand, defined as energy consumed by final users across the economy.

[2] In February 2026, after modelling for this report was complete, the Government of Canada announced that it would repeal this standard (the Electric Vehicle Availability Standard). In its place, the government announced various plans and an aspirational goal of a 90% EV adoption rate by 2040. These changes will be reflected in future versions of Canada’s Energy Future.

Figure ES.3: End-use demand by fuel in all scenarios

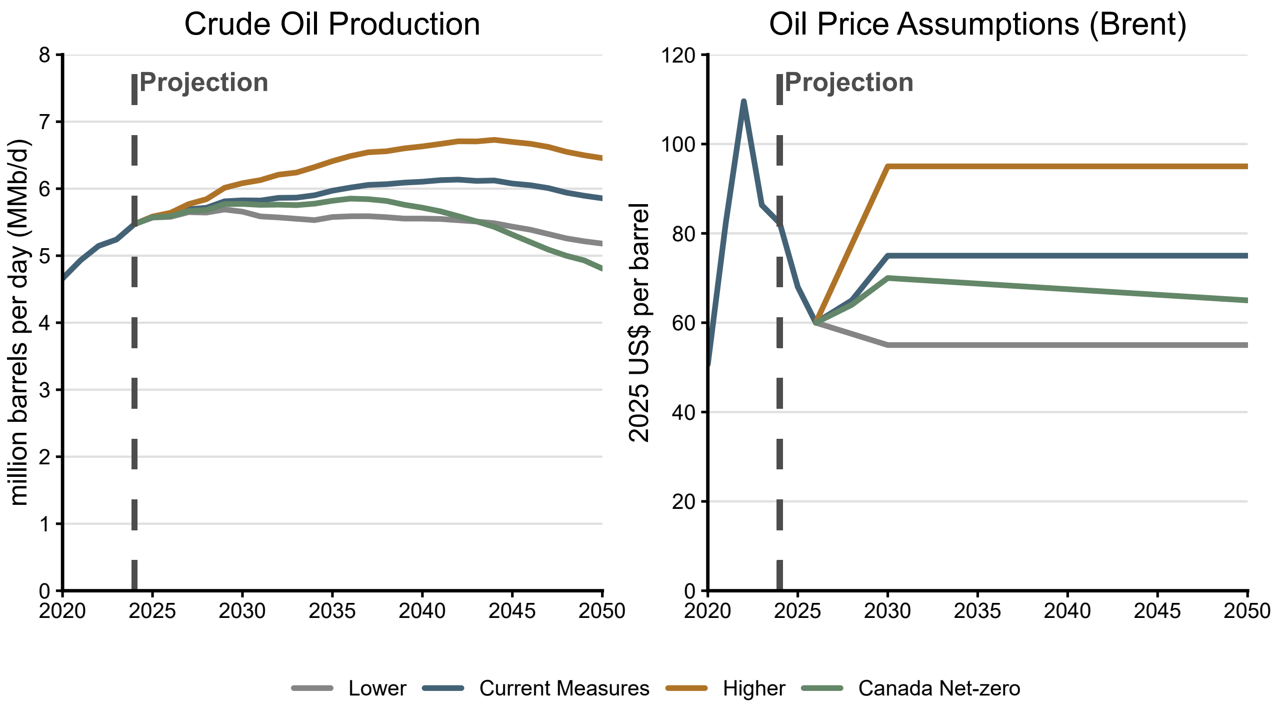


2 Canadian oil production sees short-term growth, with the long-term outlook tied to global prices.

Depending on the scenario, crude oil production ranges from modest decline to solid growth by 2050 (–12% to +18%). Global oil prices are the key driver of production long term but many other factors, including future investment trends and technology, also play an important role.

In every year since 2021, Canadian crude oil production has hit new highs, with production averaging 5.5 MMb/d in 2024 and growing even further in 2025. Most scenarios show potential for further growth, depending on the underlying assumptions. In our modeling, global oil prices are key drivers of production trends (Figure ES.4). As prices rise, there is a greater incentive for producers to increase production. Led by growth in the oil sands, total oil production peaks at 6.1 million barrels per day (MMb/d) in Current Measures by 2042 and 6.7 MMb/d in the Higher scenario in 2044. Production peaks at 5.7 MMb/d in 2029 in the Lower scenario, and 5.9 MMb/d in 2036 in Canada Net-zero, before gradually declining.

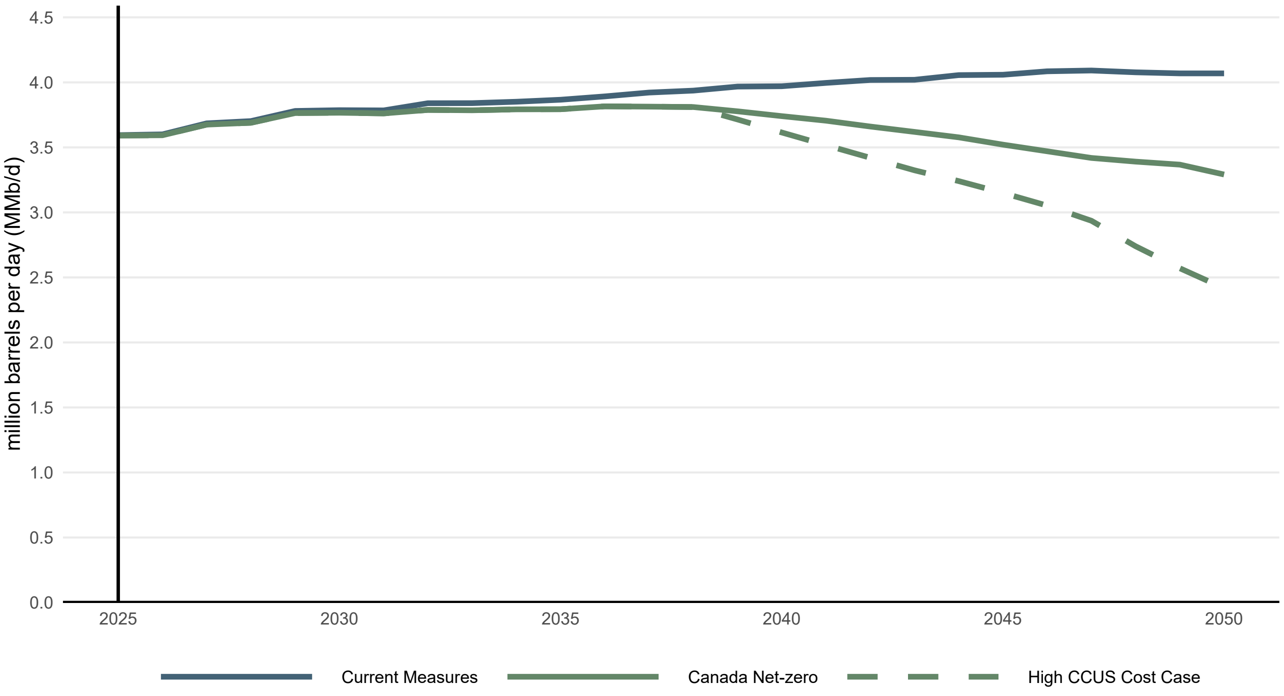
Figure ES.4: Total crude oil production and global oil price assumptions (Brent), all scenarios



By 2050, Canadian crude oil production is between 4.8 and 6.5 MMb/d across the scenarios. This range is large—1.7 MMb/d, or 30% of current production. Producer capital allocation, and producer expectations on factors such as available pipeline capacity, commodity prices, and policies, will influence future investment levels. Our projections are premised on producers continuing to behave as they have in recent years. Should producer behaviour change in the future, production growth could be meaningfully higher or lower than the scenarios in this report project, even under similar price assumptions.

In Canada Net-zero, we assume global oil prices are moderately lower than Current Measures, contributing to limited growth and eventually declining production to around 5 MMb/d by 2050. Producers are also significantly reducing their emissions in this scenario by building carbon capture, utilization, and storage (CCUS) capacity. Our CCUS cost assumptions play an important role in how much of the technology is adopted in our scenarios. CCUS remains an emerging technology with highly uncertain future costs. To explore this uncertainty, we developed a High CCUS Cost sensitivity case. This sensitivity case starts with the same assumptions as Canada Net-zero but uses CCUS costs for oil sands operations that are about double those used in Canada Net-zero. Faced with higher CCUS costs, oil sands producers increasingly choose to shut down production instead of applying more costly CCUS or other, more expensive decarbonization options. In the High CCUS Cost sensitivity case, oil sands production trends 27% lower than Canada Net-zero by 2050 (Figure ES.5), highlighting how significantly future production could vary in this sort of scenario.

Figure ES.5: Oil sands production in Current Measures, Canada Net-zero, and the High CCUS Cost sensitivity case



3 The size of future increases in Canadian natural gas production hinges on LNG.

Natural gas production grows in all scenarios, ranging between 21 Bcf/d and 32 Bcf/d in 2050. Natural gas prices and assumed LNG export volumes drive these trends.

Like crude oil, natural gas production hit record highs in 2024, reaching 18.3 billion cubic feet per day (Bcf/d), and continued to grow in 2025. By 2050, natural gas production reaches 27 Bcf/d in Current Measures, and 32 Bcf/d in the Higher scenario. Canada Net-zero and the Lower scenario converge to around 21 Bcf/d in 2050 (Figure ES.6). Natural gas production growth is largely centered in the Montney area in Northeast British Columbia and Northwest Alberta.

Our assumptions about natural gas prices and future LNG export levels are an important driver of production growth (Figure ES.7). In Current Measures, we assume 6.1 Bcf/d of natural gas goes to LNG by 2050 (48 million tonnes per annum (MTPA)), 7.9 Bcf/d in the Higher scenario (62 MTPA), and 4.3 Bcf/d in the Lower scenario and Canada Net-zero (33 MTPA). In all our scenarios, most incremental natural gas production goes to LNG exports. In 2050, LNG makes up between 20-25% of total production across all scenarios.

Figure ES.6: Total natural gas production in all scenarios

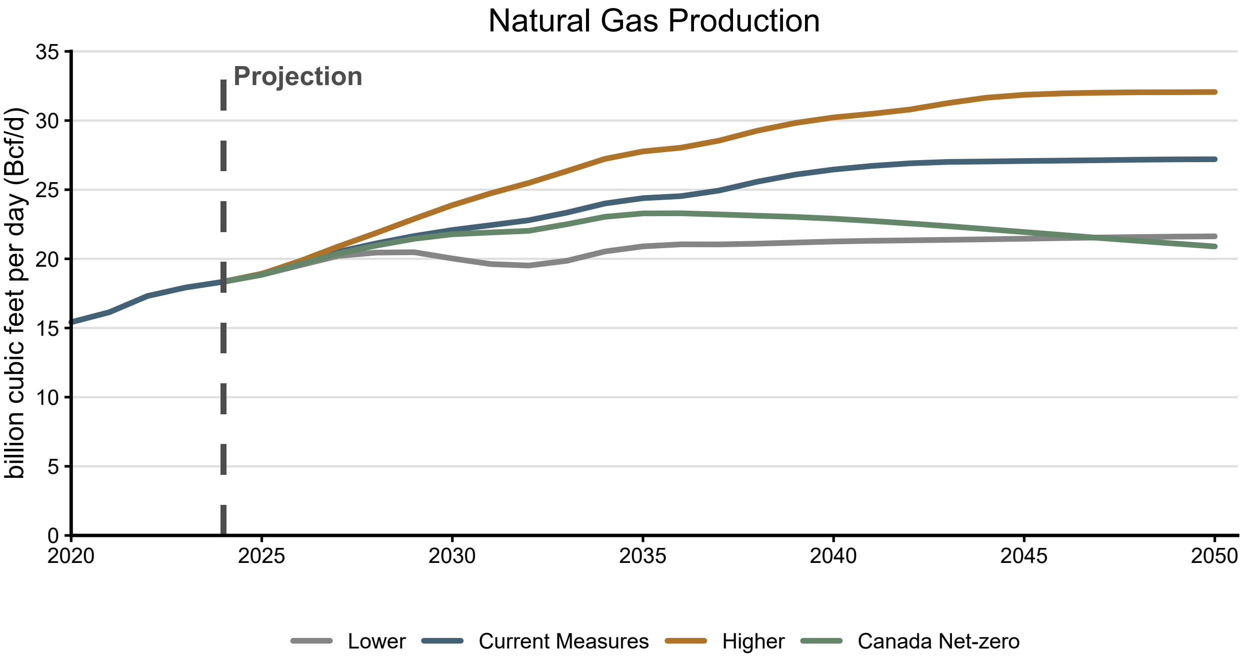
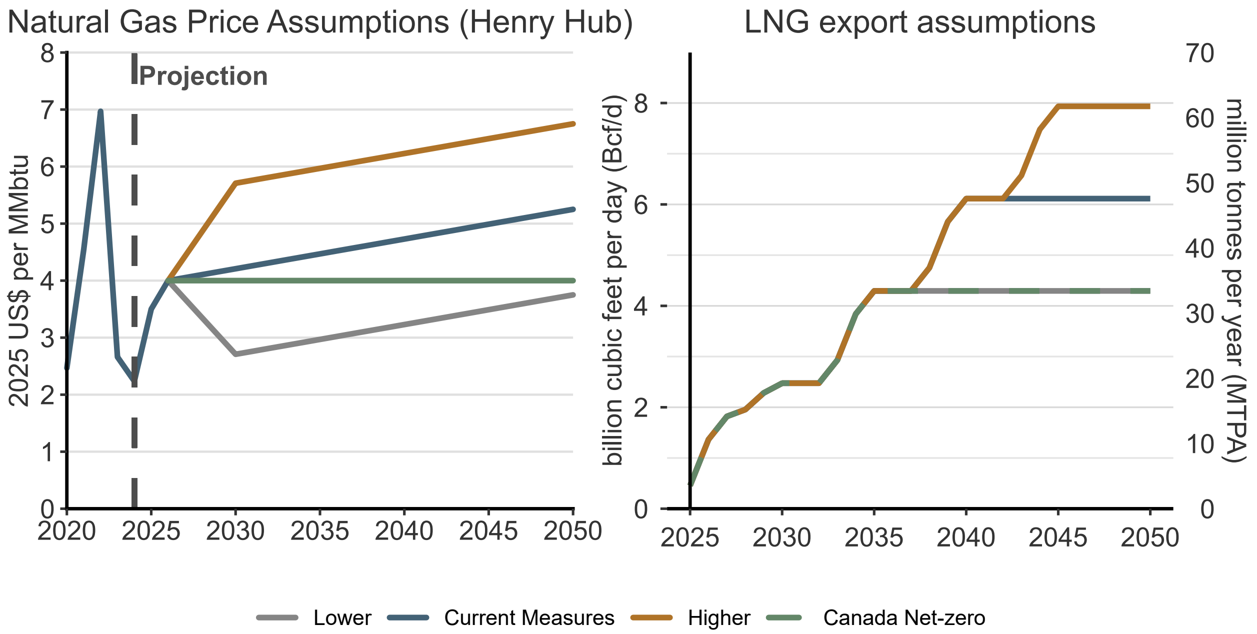


Figure ES.7: Natural gas price (Henry Hub) and LNG export assumptions

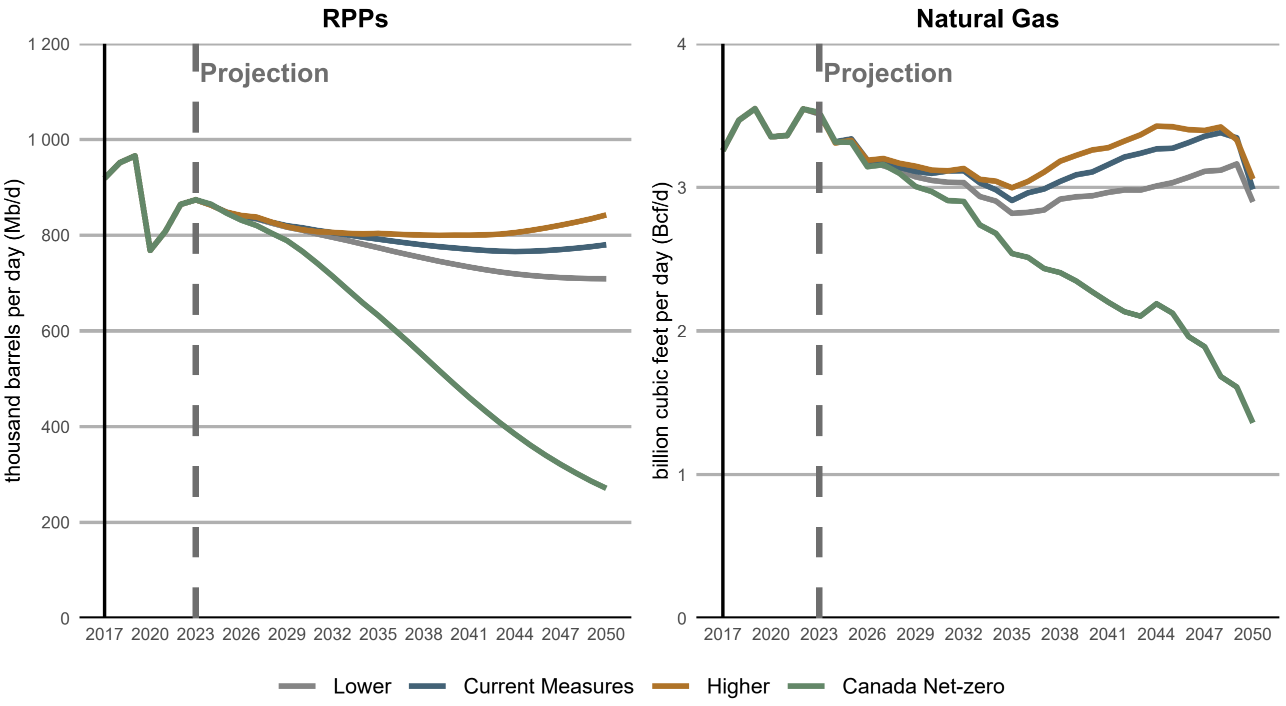


4 Oil and natural gas use in Central Canada is relatively stable under most scenarios, with the region remaining reliant on deliveries from the U.S. under current pipeline configurations.

In most of our scenarios, central Canada's refined petroleum product and natural gas use stays relatively stable, such that the region's dependence on natural gas and crude oil produced in, or transiting through, the U.S. would continue based on current pipeline configurations. The region's use of these commodities falls steadily in the Canada Net-zero scenario, which could increase its self-sufficiency.

Ontario and Quebec (i.e. Central Canada) depend on crude oil and natural gas from outside the region to meet their needs. The major pipeline systems delivering western Canadian crude oil and natural gas to the region currently have limited capacity to increase the volumes they deliver into central Canada. In addition, some segments of those pipelines transit through the U.S. before reaching central Canada. Accordingly, in the Current Measures, Lower and Higher scenarios, the region's relatively steady use of refined petroleum products (RPPs) and natural gas over the projection period (Figure ES.8) implies that the region's energy security would not significantly change, absent major infrastructure changes. In Canada Net-zero, lower RPP and natural gas use over the projection period could enhance energy self-sufficiency by increasing the share of energy that could be produced locally, such as electricity and hydrogen.

Figure ES.8: Ontario and Quebec combined RPP and primary natural gas demand, all scenarios



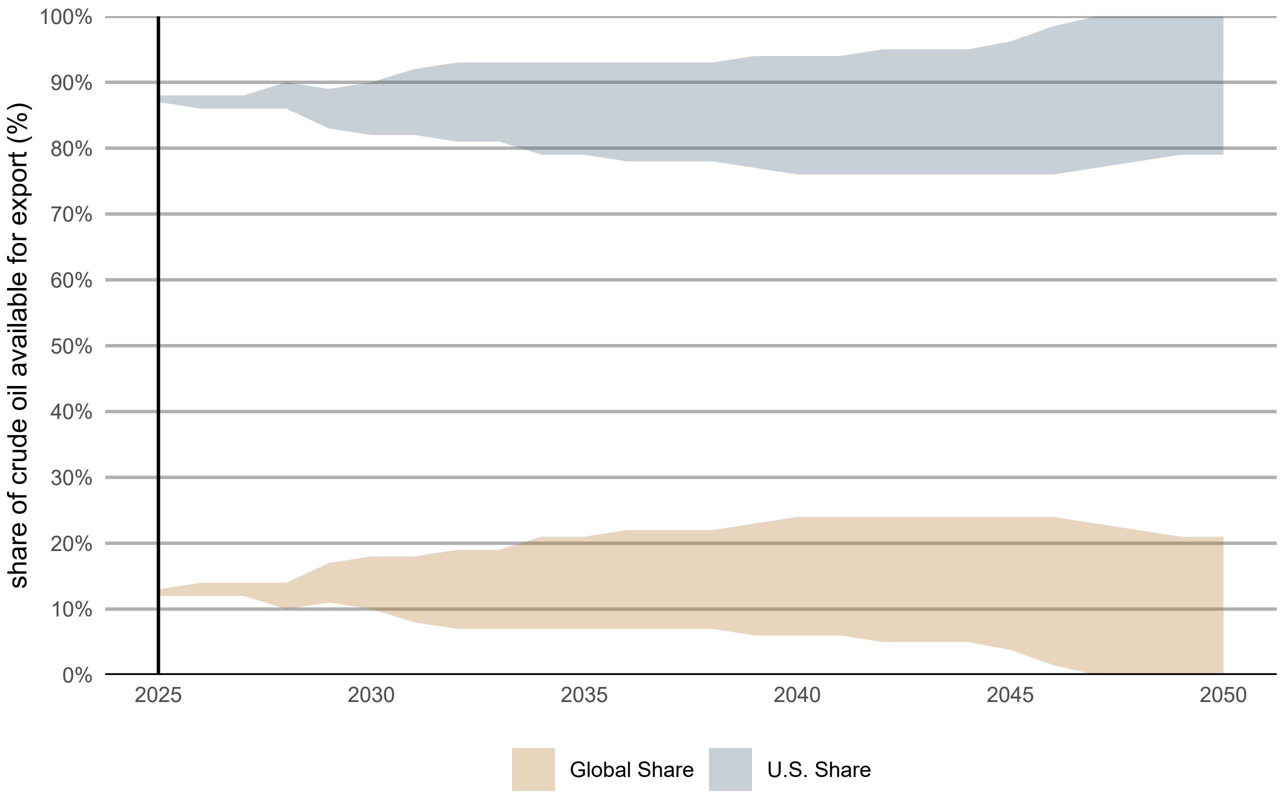
5 In all our scenarios, Canada continues to send most of its oil exports to the U.S. if existing pipeline infrastructure is used much like it is today.

In all scenarios, crude oil production does not change enough to, on its own, markedly improve the diversity of Canada's oil exports. Export diversity will depend, in large part, on investment decisions over the coming decades.

The vast majority of crude oil pipeline capacity exiting western Canada delivers to United States (U.S.) markets. Limited diversity in export markets can increase vulnerability to disruptions affecting crude oil producers and the broader economy.

The projections indicate that there is some potential to diversify Canada's crude oil trade (Figure ES.9), though more significant change may be more challenging given the extent of existing infrastructure that is oriented towards the U.S. Diversification could be higher if crude oil production ends up being higher than in the scenarios in this report, which would lead to a greater increase in crude oil available for export and potential to reach global markets. Greater diversification could also be realized if crude oil pipeline capacity to access global markets was expanded such that overall capacity is well above crude oil available for export in our scenarios, and that additional capacity draws volumes away from the U.S. market.

Figure ES.9: Potential range of market share, global and U.S. markets, all scenarios



6 Rising Canadian power demand is met by surging wind generation and a diverse mix of other supply sources.

By 2050, electricity generation ranges from 30% higher, to more than double, current levels across the scenarios. The share of non- and low-emitting generation, which is about 80% currently, increases to over 96% in all scenarios.

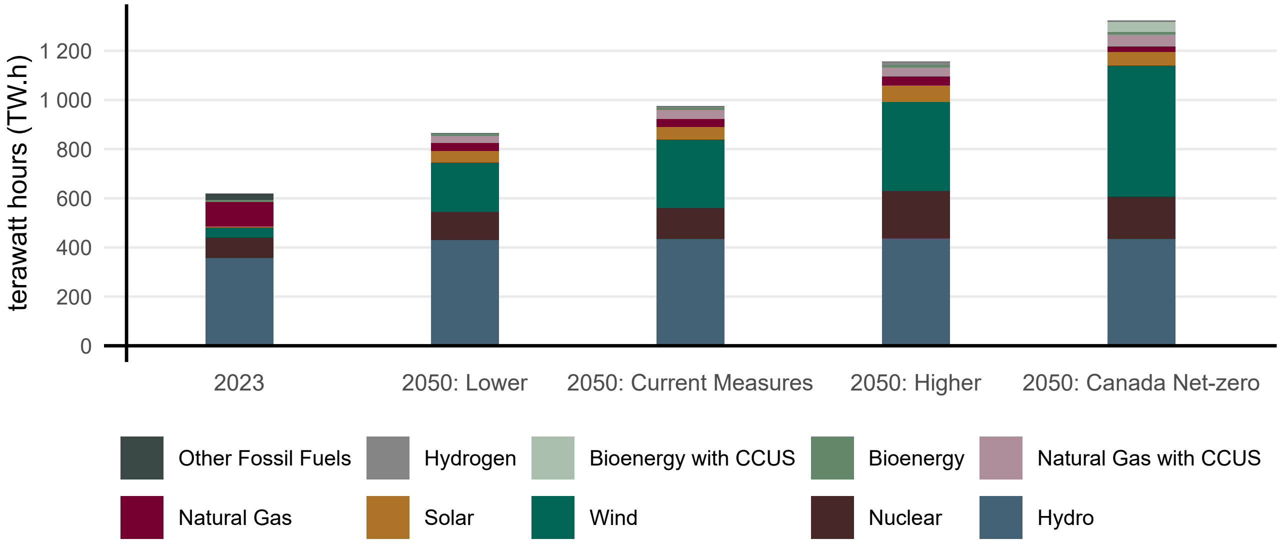
All four scenarios see a significant shift in the electricity generation mix by 2050 (Figure ES.8). The key drivers for this change are:

1. Growing electricity demand in all scenarios
2. Policies aimed at reducing the emission intensity of the electricity system
3. Falling cost of wind and solar generation

All scenarios add more generation to meet rising demands, and by far the largest incremental source is wind energy. Increasing levels of variable renewable energy are supported by increasing generation from more stable and dispatchable sources, including hydroelectricity, nuclear, and natural gas with CCUS technologies. Natural gas generation without CCUS declines over the projection period, although its capacity remains near current levels to help support grid reliability. Canada Net-zero sees the addition of bioenergy generation with CCUS, a negative emission technology, which helps offset emissions from other sectors.

All scenarios feature additional non- and low- carbon generation by 2050, but the amount varies. In the Lower scenario, total generation increases by 245 terawatt hours (TWh), whereas in Canada Net-zero, generation increases by 705 TWh.

Figure ES.10: Electricity generation by technology



Supply chain resiliency

As part of our analysis on energy security, we review Canada's supply chain resiliency for growing the electricity system. Growing Canada's electricity supply as depicted in all scenarios will require considerable investment. These investments will depend on a complex global supply chain involved in producing physical components such as solar panels or natural gas turbines. The manufacturing of those components, and the extraction and processing of materials required to manufacture them, is often highly concentrated in individual countries, which is a risk to the resiliency of the supply chain. If the trend of growing electricity use around the world continues and possibly accelerates, there is potential for supply chain challenges to impact the cost and availability of different technologies, which could impact future generation trends.

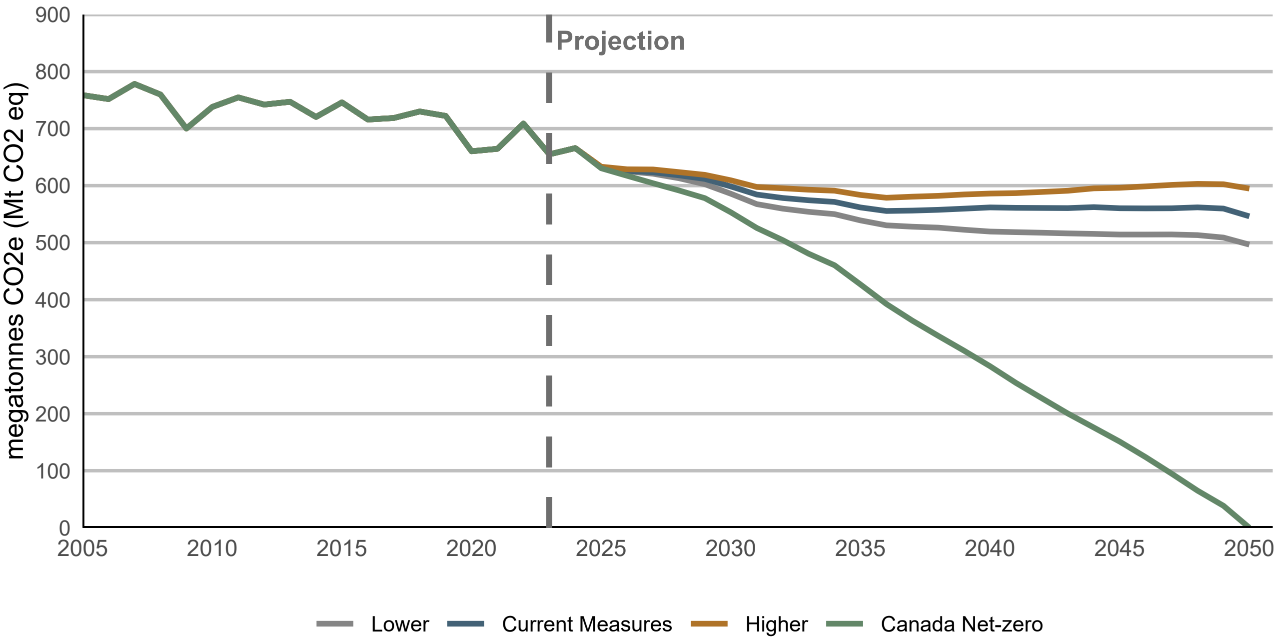
7

Canadian GHG emissions fall in all scenarios but largely level off around 2035 without more climate action over the long term.

Decarbonizing the electricity system is an important driver of emission reductions in all scenarios but overall reductions largely plateau by around 2035 under current policies. Reaching net-zero by 2050 involves an economy-wide transformation towards low carbon technologies.

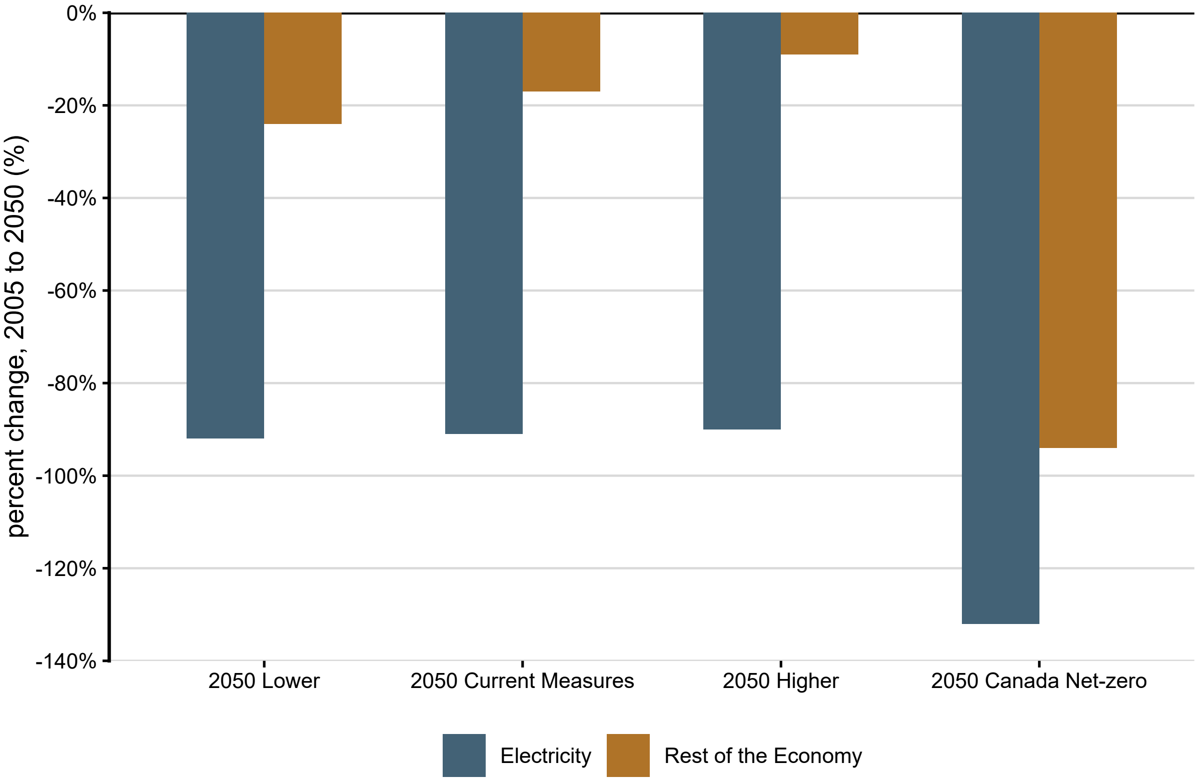
Canada's GHG emissions fall in all scenarios (Figure ES.9). In Current Measures, Higher, and Lower scenarios, policy assumptions are fixed at current levels. This leads to falling emissions in the near term, but these reductions plateau—or in the Higher scenario, gradually reverse later in the projection. By 2050, GHG emissions in Current Measures are 28% below the 2005 benchmark year, and 17% lower than 2023 levels. The Higher and Lower scenarios provide a moderate range around this level, with the Higher scenario emissions 9% above Current Measures, and the Lower scenario 9% below, by 2050. Comparing these scenarios to Canada Net-zero, where emissions in 2050 have a predetermined endpoint, shows that additional policy action is required to achieve net-zero emissions.

Figure ES.11: Net GHG emissions, all scenarios



Across the economy, the electricity sector shows the greatest emission reductions, falling over 90% across the Current Measures, Higher and Lower scenarios by 2050 compared to the 2005 benchmark year. This deep decarbonization of the electricity sector exceeds the reductions of many other sectors even in Canada Net-zero. In Canada Net-zero, the electricity sector goes even further and becomes net-negative emissions through power generated using bioenergy coupled with CCUS technology. The Canada Net-zero scenario shows a pathway where the rest of the economy adopts transformative levels of new, low-carbon technologies (Figure ES.10).

Figure ES.12: Percent change in GHG emissions, 2005 to 2050 by scenario and sector



Introduction

Canada’s Energy Future 2026: Energy Supply and Demand Projections to 2050 is the latest long-term outlook from the Canada Energy Regulator (CER). The Canada’s Energy Future series explores how Canada’s energy system might evolve. Using economic and energy models, we examine how energy supply and demand for energy could change under a range of assumptions from now until 2050.

Since its first publication in 1967, the Canada’s Energy Future series has provided Canadians with scenario-based analysis to inform energy dialogue and decision making. Each edition reflects both continuity and change: continuity in transparent modeling and scenarios and change in the evolving coverage of energy systems.

Since Canada’s Energy Future 2023 was released in 2023, the Canadian and global energy context has been shaped by shifting trade patterns, geopolitical tensions, and evolving climate policy. At the same time, rapid technological developments, particularly in artificial intelligence, and electrification, have the potential to reshape how Canadians produce and use energy.

In this context, this report introduces two new scenarios—Higher scenario and Lower scenario—that create a range of outcomes around the baseline Current Measures scenario. We also update our Canada Net-zero scenario, which examines one possible pathway for Canada to achieve net-zero greenhouse gas emissions by 2050. The report also includes thematic sections on energy security, trade diversification, and resilience, which explore questions of energy self-sufficiency, supply chain resiliency, and trade diversification. It also adds a section on Indigenous perspectives on the future of energy in Canada, highlighting insights shared by Indigenous Peoples on the roles they play today and the roles they seek to play in shaping the future of energy in Canada.

Canada's Energy Future 2026 – Scope and Limitations

Scenarios can be useful tools in exploring and understanding potential future pathways for Canadian energy. At the same time, there are important limitations to this analysis:

- **The results in this report are not predictions about the future or policy recommendations. Rather, they are the product of scenarios based on a specific set of assumptions.**
- Scenarios provide a range of potential outcomes for the future, and they are also useful to compare against one another. Relying on just one scenario to understand the energy outlook can give rise to a false sense of certainty about what could happen in the future. The similarities and differences across the scenarios often provide more useful insights than a single scenario in isolation.
- We do not assign likelihood or probability to any of the scenarios, and they do not encompass the full range of future possibilities.
- Inclusion or omission of specific projects in a scenario does not imply a prediction of regulatory outcomes or investment decisions.
- The future of energy in Canada will depend on much broader factors than those driving the projections in this report. Many of these are beyond the scope of our analysis. These include climate change[3], evolving societal preferences, regulatory frameworks and policy decisions, socioeconomic and affordability considerations, and Indigenous rights, partnerships and equity ownership in energy projects.
- The CER's energy information work, which includes Canada's Energy Future series, is separate from the adjudicative role of the Commission of the CER. The Commission is responsible for making independent adjudicative decisions and recommendations under the Canadian Energy Regulator Act (CER Act)[4] and other legislation. The Commission considers each matter before it based on the evidence parties submit in a proceeding. If a party wishes to rely on material from this report in any regulatory proceeding before the CER's Commission, it may submit the material, just as it may submit any public document. This evidence may be subject to questions and/or cross-examination from parties.
- Policies that were enacted after the end of November 2025, like the Enhanced Methane Regulations, are excluded from the Current Measures, Higher, and Lower scenarios.

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[3] Many of the impacts of climate change on Canada today are described in Canada's National Adaptation Strategy. These impacts include more frequent and intense weather events, such as floods and heat waves, and more gradual impacts such as permafrost thaw and coastal erosion. According to the United Nations International Panel on Climate Change, global surface temperatures are very likely to increase until at least 2050. This increase suggests that the impacts of climate change on the energy system and economy will increase over the projection period. Our models do not currently account for the wide range of climate impacts on the energy system and economy.

[4] The Canadian Energy Regulator Act (CER Act) is the foundation for nearly all that we do. Core to the governance of our organization is a clear separation between the operational and adjudicative functions of the CER.

Scenarios and Assumptions

Scenarios

Scenarios are central to the Canada's Energy Future series. They provide a structured way of exploring how Canada's energy system could evolve under different sets of assumptions. Scenarios are not forecasts or predictions. They are tools that help us test how supply and demand for energy may change under varying policy, technology, market, and economic conditions.

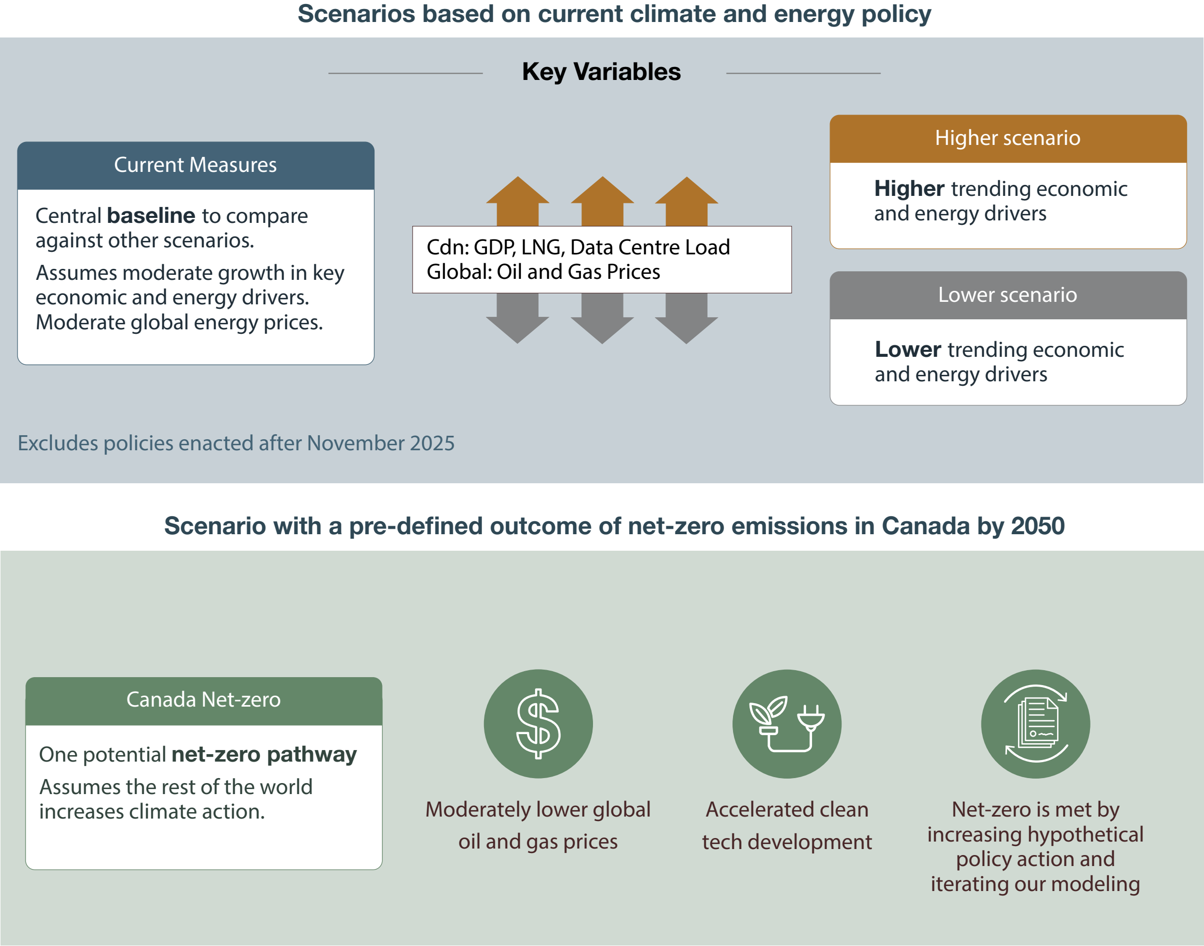
This report includes four scenarios to explore Canada's energy outlook. **Current Measures** is our version of a traditional baseline scenario often used in energy outlooks. It has a similar set of assumptions as the baseline scenarios used in other outlooks, such as Environment and Climate Change Canada (ECCC)'s GHG emission projections (their "With Measures" scenario) and the U.S. Energy Information Administration's Annual Energy Outlook (their "Reference Case"). This type of scenario includes moderate economic growth and energy prices, policies currently in place, and moderate technological progress. Although we refer to it as a baseline, it is not a prediction or our view of a most likely scenario, and we do not assign probabilities to any of our scenarios. Our Current Measures scenario is most useful in comparison with other scenarios.

To explore some of the major uncertainties Canada and the world face when it comes to energy and the economy, we have developed two new scenarios: The **Higher scenario** and **Lower scenario**. These scenarios explore what might happen if some key drivers of Canada's energy system—Canadian GDP growth, LNG exports, data centre load growth, and global oil and natural gas prices—trend higher or lower, respectively, compared to Current Measures. These scenarios effectively create a range around Current Measures.

To explore the potential impacts of a faster pace of climate action, we also include an update to the Canada Net-zero scenario, introduced in EF2023. Canada Net-zero is different because it begins with a predetermined end point—net-zero emissions for Canada in 2050—and then explores the question “what might a pathway to that end point look like?”. This scenario assumes that, in addition to Canada reaching net-zero by 2050, the rest of the world also increases its pace of climate action[5] to meet current pledges but falls short of the ambitious transformation needed to limit warming to 1.5°C above pre-industrial levels. This leads to lower global oil and natural gas demand than in a baseline scenario (and hence lower oil and natural gas prices) and lower clean technology costs, as Canada benefits from increasing technological development both domestically and in the rest of the world.

Figure A.1 summarizes the scenario assumptions and highlights the key uncertainties each is designed to explore.

Figure A.1: Scenarios and assumptions



Scenarios based on current climate and energy policy

Key Variables

Current Measures

Central **baseline** to compare against other scenarios.

Assumes moderate growth in key economic and energy drivers. Moderate global energy prices.

Cdn: GDP, LNG, Data Centre Load
Global: Oil and Gas Prices

Higher scenario

Higher trending economic and energy drivers

Lower scenario

Lower trending economic and energy drivers

Excludes policies enacted after November 2025

Scenario with a pre-defined outcome of net-zero emissions in Canada by 2050

Canada Net-zero

One potential **net-zero pathway**

Assumes the rest of the world increases climate action.

Moderately lower global oil and gas prices

Accelerated clean tech development

Net-zero is met by increasing hypothetical policy action and iterating our modeling

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[5] This scenario is informed by a range of international outlooks that explore pathways consistent with limiting global temperature rise. While the scenario is not directly linked to a single climate model, its underlying assumptions draw from sources such as the IEA and Rystad Energy, for cases that generally align with global temperature outcomes that fall short of the aspirational goal of limiting warming to 1.5°C above pre-industrial levels, and that are closer to 2°C.

Key Assumptions

Domestic climate policy

Domestic climate policies include laws, regulations, and programs put in place by governments with the goal of reducing GHG emissions. Such policies can affect the trajectory of Canada's energy system. This section outlines assumptions about the climate policies modeled in each scenario in this report. Additional details are available in Appendix 1: Domestic Climate Policy Assumptions.

In Current Measures, Higher scenario, and Lower scenario, policies that are currently in place were included. A policy is "in place" if it was enacted before the end of November 2025. Due to this timing, we do not include the Enhanced Methane Regulations, published in December 2025, in Current Measures, Higher scenario, and Lower scenario.

Some key policies that have been recently enacted or changed include:

- **Clean Electricity Regulations**: Set an annual emissions limit for electric power generating units that burn any amount of fossil fuels.
- **Electric Vehicle Availability Standard**: A regulated sales target for zero emission vehicles (ZEVs) that auto manufacturers and importers must meet. The modeling includes targets of 60% for 2030 and 100% by 2035 and reflects the pause in the 2026 target (20%) announced in September 2025. The Government of Canada announced in February 2026 that it would repeal the Electric Vehicle Availability Standard, which was the basis for this assumption. In its place, the government announced various plans and an aspirational goal of a 90% EV adoption rate by 2040. These changes will be reflected in future versions of Canada's Energy Future.
- **Clean Economy Investment Tax Credits**: Various investment tax credits that reduce clean technology costs. Includes CCUS, clean technology, clean hydrogen, and clean technology manufacturing. The expanded Investment Tax Credits for CCUS, as well as the Clean Electricity Investment Tax Credit, as announced in the Federal Budget 2025, are reflected.
- **Removal of consumer carbon pricing**: The modeling reflects the removal of the consumer carbon price effective April 2025.

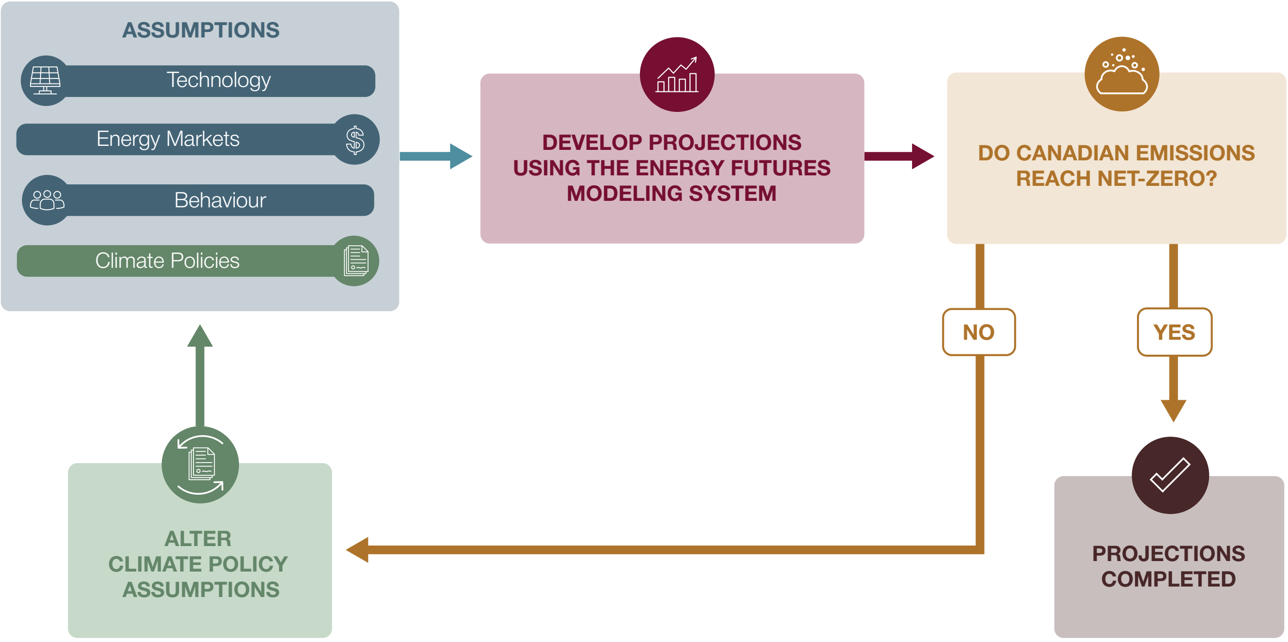
The Canada-Alberta MOU

On 27 November 2025, the governments of Canada and Alberta released the Canada-Alberta Memorandum of Understanding (MoU). In it, they make a number of commitments, and outline that they will appoint an Implementation Committee that will be responsible for delivering various outcomes, including three different agreements by 1 April 2026.

Given the subject matter of the MoU, it may impact the Canadian energy outlook, including by potentially affecting certain climate policies in Alberta, such as the Clean Electricity Regulations, industrial carbon pricing, and the regulation of methane emissions. However, we have not altered our assumptions in this report to reflect the MoU, since it did not result in final and fully detailed policy changes by our policy cutoff date of the of end of November 2025. Future changes to energy and climate policies, including any stemming from the MoU, will be reflected in future editions of the Canada's Energy Future report.

In Canada Net-zero, **we begin with the end goal in mind: net-zero GHG emissions in 2050 and use our models to identify a pathway to that point.** We do this by increasing the stringency of our policy assumptions in an iterative manner until our models show a net-zero pathway (Figure A.2).

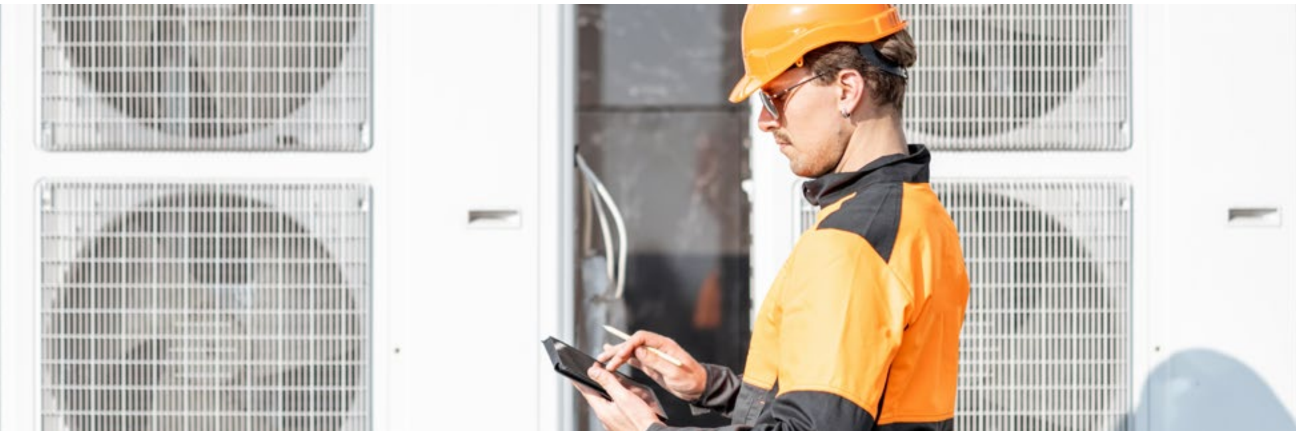
Figure A.2: Simplified iterative approach to modeling net-zero in Canada Net-zero



The specific assumptions we change to increase climate policy stringency in Canada Net-zero differs by sector. These hypothetical actions are not meant to represent likely or recommended policy. Instead, they extend the direction signaled by existing or proposed measures, such as the Clean Fuels Regulations, ZEV initiatives, and strengthened methane regulations, to illustrate a pathway consistent with achieving net-zero. Our assumptions are:

- **Clean fuels:** Anchored to the current Clean Fuel Regulations to 2030, we gradually ramp up mandated fuel emission intensity improvements post 2030, leading to higher clean fuel shares in all sectors.
- **Freight ZEVs:** Anchored to the Zero-Emission Vehicles Strategy, we assume a requirement for nearly all new freight vehicles to use zero-emission technologies by 2050.
- **Marine and aviation:** We assume an increasing requirement for low and non-emitting fuels (such as renewable diesel and sustainable aviation fuel).
- **Net-zero buildings:** We assume all new buildings require a low or non-emitting heating source as their primary technology after 2035 (with fossil fuel heat still available as back-up technology).
- **Enhanced Methane Regulations:** We assume strengthened methane regulations are implemented.[6]
- **Other sectors:** For all sectors currently facing a carbon price, we assume an aggregate cost of carbon is phased in as a hypothetical representation of additional climate policy in the future. As a hypothetical aggregate, it would represent any potential future increases to industrial pricing, as well as other potential policies applied to these sectors in the future.
- **Offsets for remaining emissions:** Our analysis assumes the development of a system to allow providers of negative emissions (including direct air capture, bioenergy with carbon capture and storage, various nature-based solutions and other carbon dioxide removal options) to be compensated for their removals at a rate equivalent to the aggregate cost of carbon.

Further details on these assumptions are available in Appendix 1: Domestic Climate Policy Assumptions.



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[6] In December 2025, the federal government published the final Enhanced Methane Regulations. This was after our modeling period, which ended in November 2025, so these final regulations are not included in the Current Measures, Higher, or Lower scenarios.

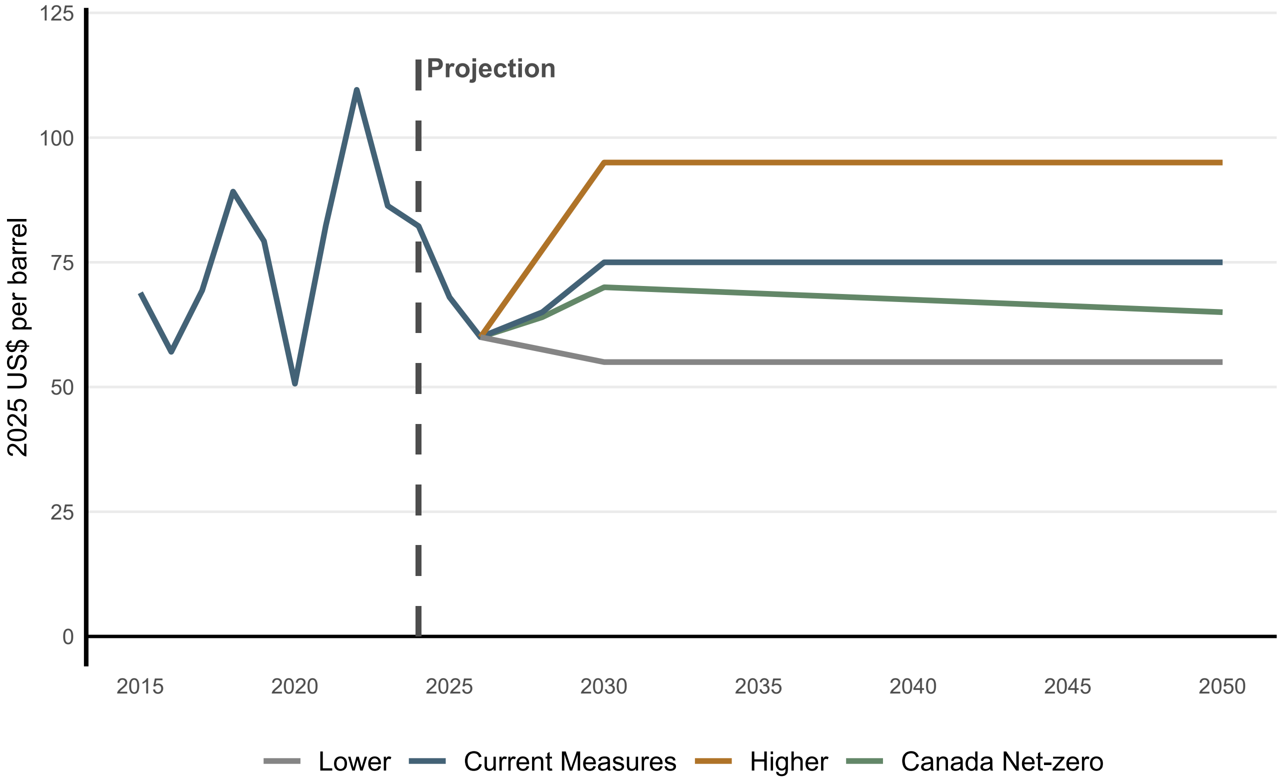
Energy Markets

Current Measures assumptions, such as global energy prices, are based on a review of baseline scenarios from various global outlooks. The Higher and Lower scenarios include higher and lower global oil and natural gas price assumptions, to test the impacts of these important drivers of Canadian oil and natural gas production on our projections.

Our scenarios are designed to span a plausible range of market outcomes, recognizing the uncertainty surrounding growth, investment, and trade. Canada Net-zero presumes that faster global climate action leads to lower global oil and natural gas demand, thus contributing to lower assumed international oil and natural gas prices than in Current Measures. We developed the Canada Net-zero oil and natural gas price assumptions by surveying various global outlooks and scenarios that reflect a world where other countries act on their climate pledges and global emissions are reduced, but not enough to reach the aspirational target of limiting warming to 1.5°C above pre-industrial levels, and are closer to 2°C.[7]

Figures A.3 and A.4 show crude oil and natural gas price assumptions, respectively.

Figure A.3: International crude oil price assumptions (Brent), all scenarios



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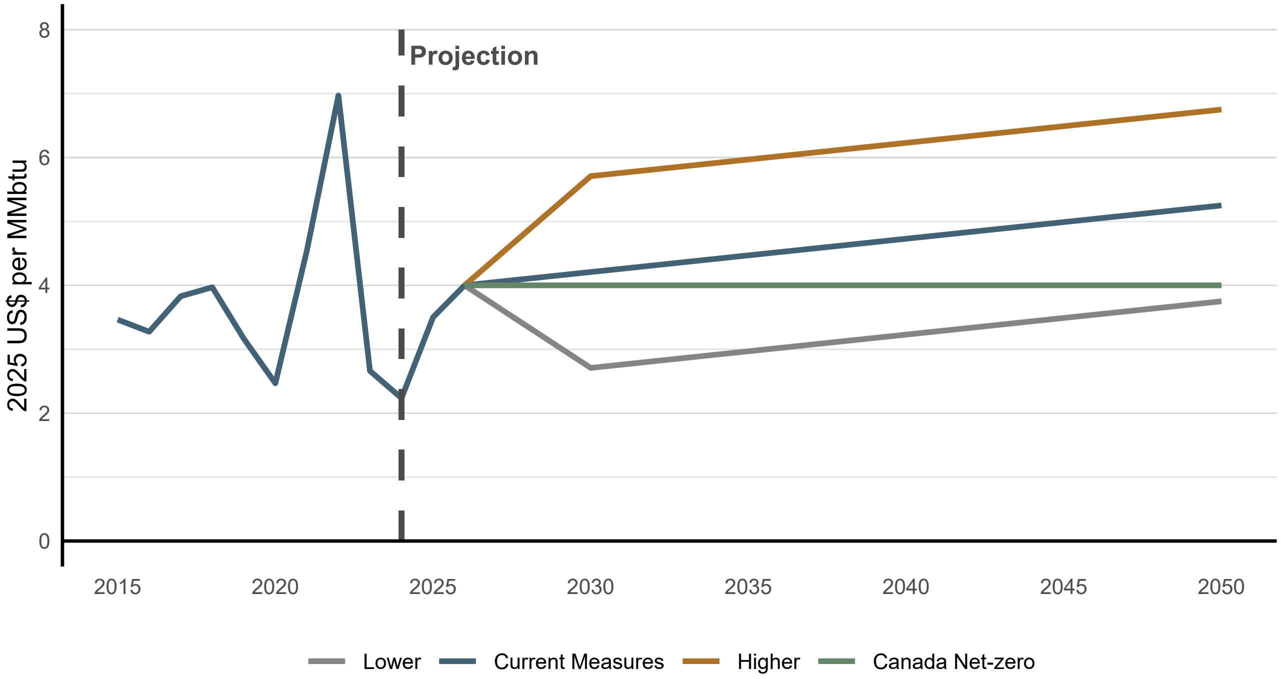
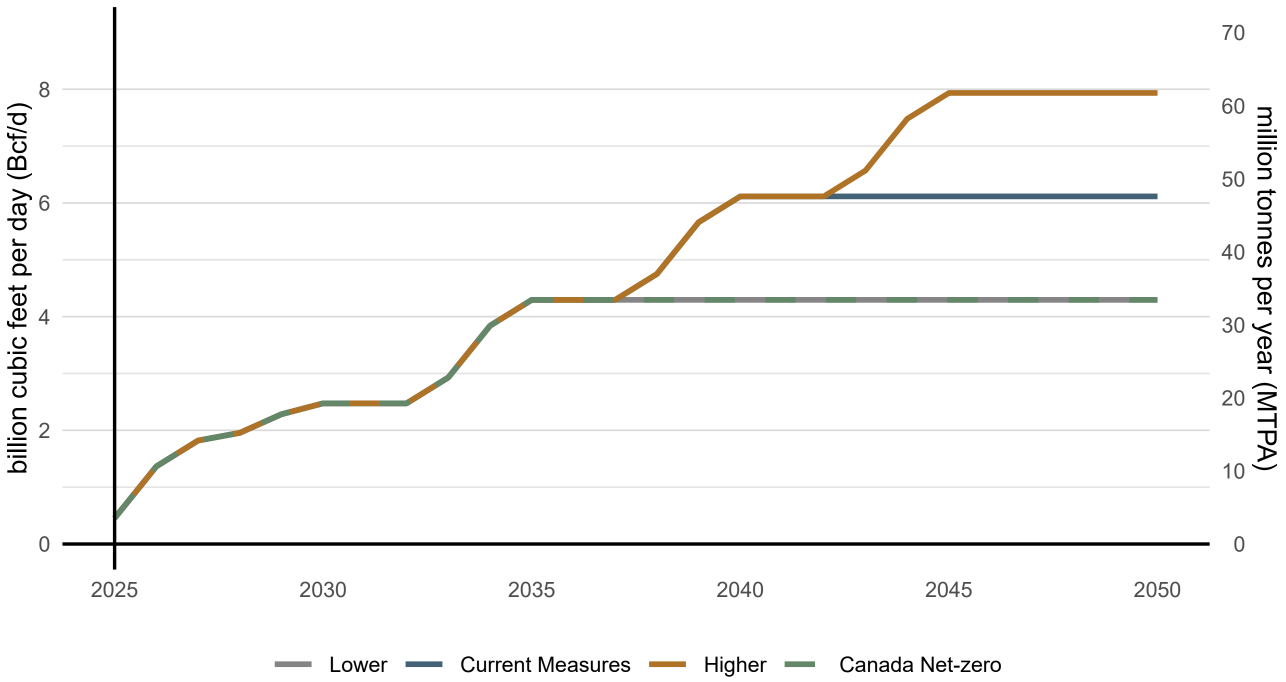
[7] The underlying assumptions in Canada Net-zero draw from sources such as the IEA and Rystad Energy, for cases that generally align with global temperature outcomes that fall short of the aspirational goal of limiting warming to 1.5°C above pre-industrial levels, and that are closer to 2°C.

Figure A.4: International natural gas price assumptions (Henry Hub), all scenarios



Canadian LNG export assumptions also differ by scenario, as shown in Figure A.5. Canadian LNG exports are an important assumption for natural gas production, because they are likely to lead to increased production to meet export demands. In Current Measures, we include all projects that are operational or under construction and assume two additional hypothetical large projects come online in B.C. in the future. In the Higher scenario, we assume three hypothetical projects, whereas in the Lower scenario and Canada Net-zero we assume one. We assume 75% of the natural gas that will be liquefied will come from natural gas production dedicated to supplying LNG facilities. This means that this 75% comes from production that only exists because LNG export capacity exists and is above and beyond what would be produced based solely on our North American natural gas price assumptions. Importantly, inclusion here has no bearing on any regulatory approvals, including by the Commission of the CER, nor does it suggest any particular outcome of regulatory processes.

Figure A.5: Canadian LNG export volume assumptions, all scenarios



Technology

Current Measures, and the Higher and Lower scenarios assume a baseline view on technological development for clean technologies. We develop these assumptions by reviewing technology cost outlooks from various agencies, such as the U.S. National Renewable Energy Laboratory and the IEA. Costs for renewables, power storage, carbon capture, and other technologies continue to decline at varying rates, depending on their current momentum and potential for further reductions.

Canada Net-zero assumes faster cost declines of clean energy technologies, reflecting a global environment of stronger climate action and greater investment, leading to additional technological advances that reduce costs. Figure A.6 compares our cost reduction assumptions for key clean technologies in Current Measures[8] and Canada Net-zero. Across these technologies, cost reductions in Canada Net-zero range around 20-60% more than in Current Measures. Full technology details (including the actual cost values and additional technologies) are available in Appendix 2: Technology Assumptions.

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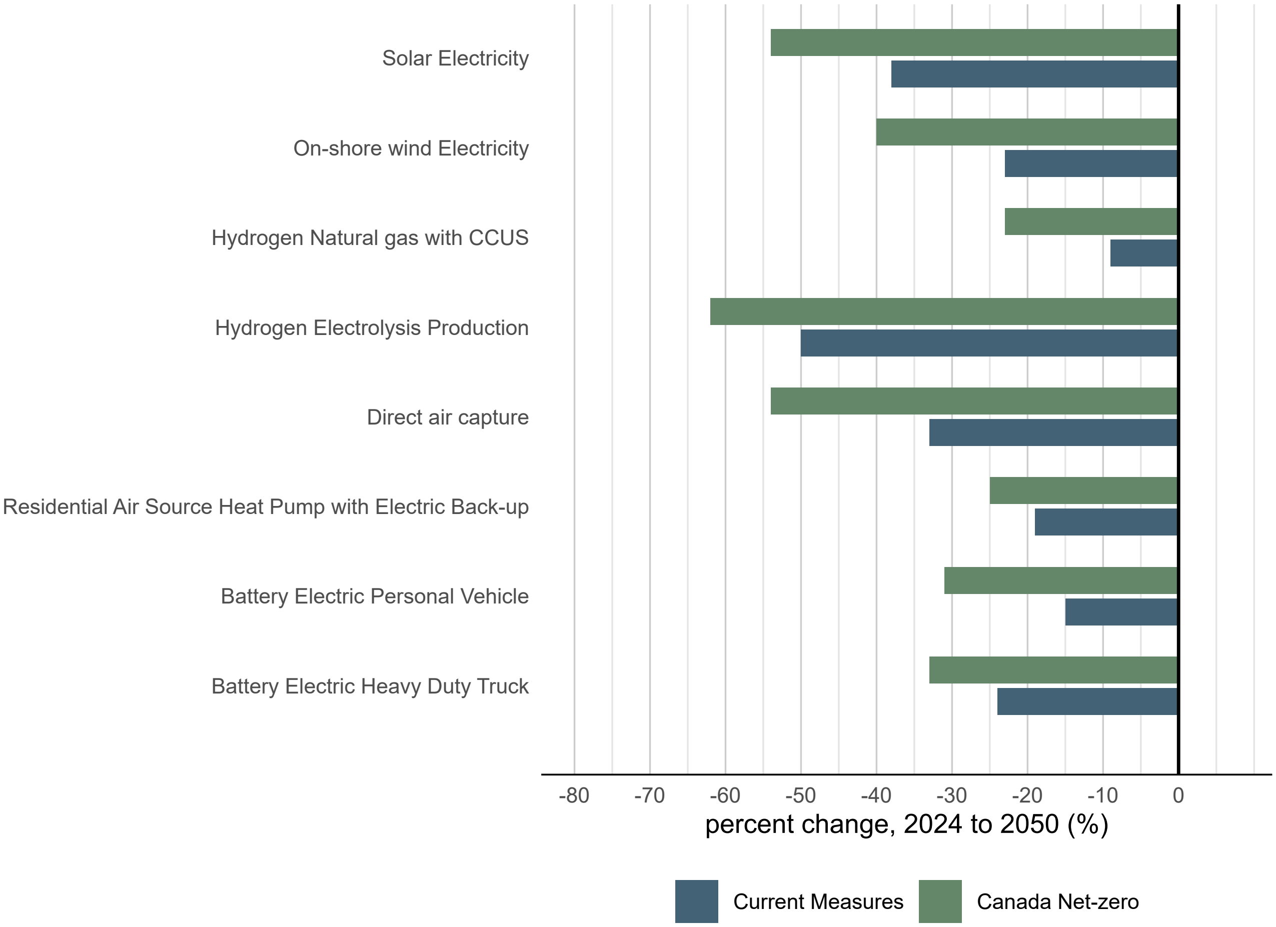
[8] Technology cost reduction assumptions in the Higher and Lower scenarios are the same as in Current Measures.

Figure A.6: Percent change in capital cost assumptions for key clean technologies, 2024 to 2050, Current Measures and Canada Net-zero



Macroeconomic Drivers

The macroeconomic outcomes contained in this report are modeled results in all four scenarios and are described in the Results chapter. They result from an iterative process where our energy system results and initial macroeconomic conditions are exchanged between the energy models and the macroeconomic model. In the Higher and Lower scenarios, we assume faster and slower economic growth, respectively. We do this by assuming demand for Canadian exports is stronger or weaker compared to Current Measures. For these scenarios, we adjusted export demand to target approximately +/- 0.4% growth in Canadian real GDP per year, compared to Current Measures. Further implications of faster or slower growth in these scenarios (such as changes to population growth, inflation, or the exchange rate) are a result of the macroeconomic modeling.

Data Centre Load Growth

Rapidly rising electricity demand from data centres is an emerging topic of interest, in both Canada and the world. Much of this growth in electricity demand is driven by the substantial power required to train large language models (LLMs), a type of artificial intelligence (AI) application, and to supply the growing public use of these applications. Many utilities are factoring in increasing data centre load growth into their future planning outlooks. Data centres pose a challenge for outlooks because they can be large and quite uncertain, depending on the development of the emerging industry.

Given the potential impact of significant data centre growth on electricity demand, we assume additional demand in the commercial sector across all scenarios. We do so because current models cannot yet reliably estimate long-term data centre demand given how new and fast evolving the industry is. For Current Measures and Canada Net-zero, we add 1.5 GW of data centre load by 2030, and 3.5 GW by 2050. This baseline view is guided by available data from Canadian utility and system operator outlooks in their baseline outlooks, with most growth occurring in Ontario, Alberta, and Quebec. In the Lower scenario, we add 0.5 GW by 2030 and 1.5 GW by 2050. In the Higher scenario, we add 2.7 GW in 2030, and 12 GW in 2050, including additions in all provinces. The range of data centre load growth in the Higher and Lower scenarios allows us to explore this emerging uncertainty. As this industry develops, actual load growth may be higher or lower than assumed in our modeling.

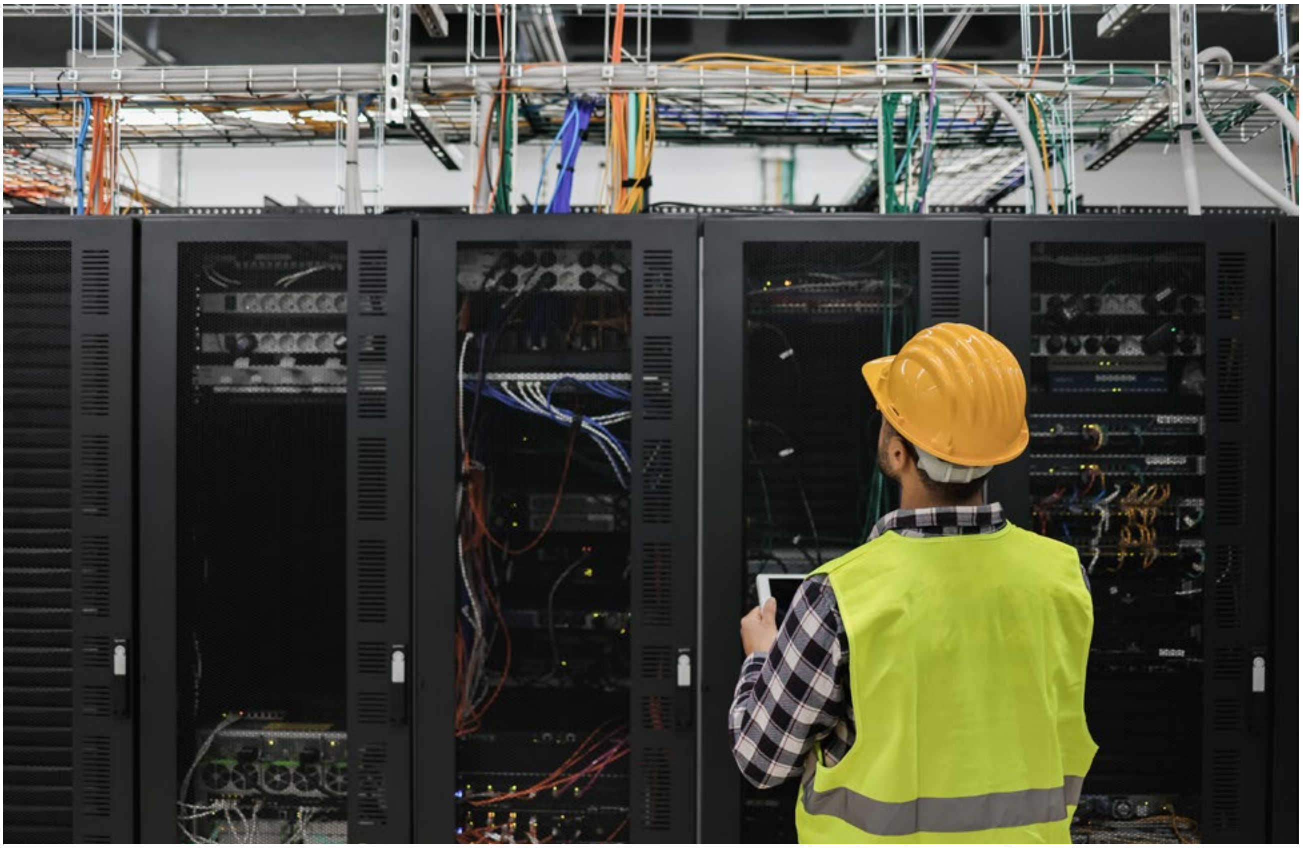


Photo credit: Cedar LNG Project, Haisla Nation and Pembina Pipeline Corporation

Indigenous Perspectives on the Future of Energy in Canada

There are many important aspects of Canada's energy future that are difficult to capture in quantitative models, including the evolving roles, priorities, and experiences of First Nations, Métis, and Inuit communities.[9] While our scenarios reflect economic, policy, and technology trends, they cannot fully account for these broader social and cultural dimensions.

Recognizing this and acknowledging the key role that Indigenous communities play in shaping the future of energy in Canada, the CER partnered with Mokwateh, an Indigenous-owned consultancy. Through this partnership, Mokwateh engaged Indigenous communities across Canada to gather their perspectives, aspirations, and concerns about the future of energy in Canada.

Through multiple interviews, focus groups, and surveys, Mokwateh engaged with 35 Indigenous participants. Mokwateh then produced a Final Report, Indigenous Leadership in Canada's Energy Transition. It summarizes and analyzes key findings, highlighting region-specific priorities, challenges, and opportunities related to energy development and consumption.

These insights were gathered in the fall of 2024, prior to the introduction of new or modified federal and provincial initiatives designed to support Indigenous participation in the energy sector. Programs such as the Canada Indigenous Loan Guarantee Program[10], alongside other evolving policies, may help alleviate some of the barriers identified by communities and create new opportunities to advance Indigenous energy priorities. The findings here reflect the perspectives shared at the time of engagement.

The key findings from this engagement are presented below. These findings supplement our scenario modelling (see textbox: *Energy Futures: Scope and Limitations*) by further exploring how the energy transition intersects with Canada's journey toward Reconciliation.

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[9] For the purposes of this report, the term ''Indigenous" refers to First Nations, Métis, and Inuit peoples, unless otherwise stated.

[10] Canada Indigenous Loan Guarantee Corporation, Canada Development Investment Corporation

It is important to acknowledge that the findings below do not fully reflect the diversity of all Indigenous Peoples, given the unique and dynamic circumstances of each community. In their own words, Mokwateh summarized the perspectives and insights they heard as follows[11]:

Key Findings

- **Clean Energy Transition:** Indigenous communities prioritize moving away from diesel dependency toward renewable and alternative energy sources such as solar, wind, hydro, and nuclear, motivated by environmental, health, and economic concerns.
- **Energy Sovereignty:** Self-determination in energy production and management is a universal priority, with communities emphasizing ownership, control, and improved reliability.
- **Economic Development:** Energy projects are viewed as opportunities for job creation, revenue-sharing, and long-term benefits.
- **Cultural and Environmental Preservation:** Safeguarding traditional practices and minimizing ecosystem impacts are essential for community trust and support.

Regional Insights

- **Eastern Canada:** Communities see opportunities in renewable adoption and infrastructure upgrades but face high costs and utility constraints.
- **Northern Canada:** Microgrids and localized solutions support sovereignty, though remoteness and harsh climates pose challenges.
- **Western Canada:** Communities are exploring hydrogen, storage, and small modular reactors, while also voicing concerns about cultural site preservation.
- **National Trends:** Many communities see alignment with Canada's climate goals, but timelines and infrastructure readiness vary. Access to clear, timely information remains a key need.

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[11] Disclaimer: The views and opinions expressed in the Mokwateh report are those of the authors or the people they engaged with, and do not necessarily reflect the official perspective of the CER. Furthermore, the inclusion of any findings or recommendations in this report should not be interpreted as an endorsement or approval by the CER. Mokwateh, an Indigenous-owned consultancy specializing in engagement and advisory services, conducted the Indigenous engagement activities and drafted its report for the CER.

Key Barriers

Communities identified financing, logistical, and regulatory challenges as significant obstacles to advancing energy projects—particularly in remote regions. High costs, limited access to capital, difficulties in deploying and maintaining infrastructure, and complex approval processes were recurring concerns, alongside the need for stronger Indigenous representation in governance.

Indigenous Energy Priorities

- **Expand Indigenous-led projects** through ownership, co-management, and equitable revenue-sharing.
- **Invest in infrastructure** to improve grid connections, microgrids, and storage solutions.
- **Build capacity** via training, energy literacy, and local expertise in emerging technologies.
- **Foster authentic engagement** by ensuring Free, Prior, and Informed Consent (FPIC) and transparent dialogue.

The Mokwateh report highlights the central role of Indigenous leadership in shaping Canada's energy transition. Themes such as energy sovereignty, renewable power adoption, and capacity building reflect both the aspirations and the concerns of many Indigenous communities. These perspectives underline the need to consider cultural, social, and environmental factors in planning Canada's future energy system, and point to opportunities for collaboration and innovation in overcoming challenges. This engagement strengthened our understanding of key opportunities, uncertainties, and implementation realities that extend beyond quantitative analysis.

Scenario Results

This section provides an overview of this report's modeling results for the four scenarios. Additional details, including breakdowns by region, technology, and sector, can be found in the Energy Future datasets. Ways to access and explore the data:

- **Explore Canada's Energy Future:** Our interactive visualization tool.
- **Data Appendix:** Customizable, downloadable tables arranged by category.
- **Open Government:** Full datasets available in machine-readable format.
- **Figure Data:** Excel download of the data behind the figures in this report.

Historical data in Canada's Energy Future 2026

The modeling and analysis for this report took place in late 2025. Our models rely primarily on historical data, which are actual values, up to, and including, 2023 for electricity and energy use statistics, and 2024 for oil and natural gas production statistics. Data points after these dates should be considered as projections. Historical statistics can be revised, and the values in this report will not account for adjustments made after mid-2025.

Energy Demand

This section discusses end-use (or “secondary”) energy demand[12] projections. End-use demand includes consumption of energy commodities, including electricity, hydrogen and fuels used for transportation, space heating, industrial processes, as well as non-combustion purposes such as lubricants and petrochemical feedstocks. It does not include the energy used to produce electricity and hydrogen.[13,14]

End-use demand grows moderately in Current Measures, faster in the Higher scenario, and slower in the Lower scenario and Canada Net-zero (Figure R.1). Overall, end-use demand grows by 11% in Current Measures from 2023 to 2050, compared to over 50% growth in real GDP over the same period. This implies Canada’s energy intensity, measured as energy use per $ of real GDP, falls by an average of 1.1% per year.[15]

Relative to Current Measures, end-use demand is 12% higher by 2050 in the Higher scenario (about +1,560 PJ) and 10% lower in the Lower scenario (about -1,220 PJ). These trends are the result of the range of economic growth projections, higher or lower oil and natural gas activity, and higher or lower assumptions related to energy prices and data centre load growth. In Canada Net-zero, total demand is similar to the Lower scenario, but for different reasons. In Canada Net-zero, lower demand compared to Current Measures is driven by improving energy efficiency and adoption of more efficient electric technologies.

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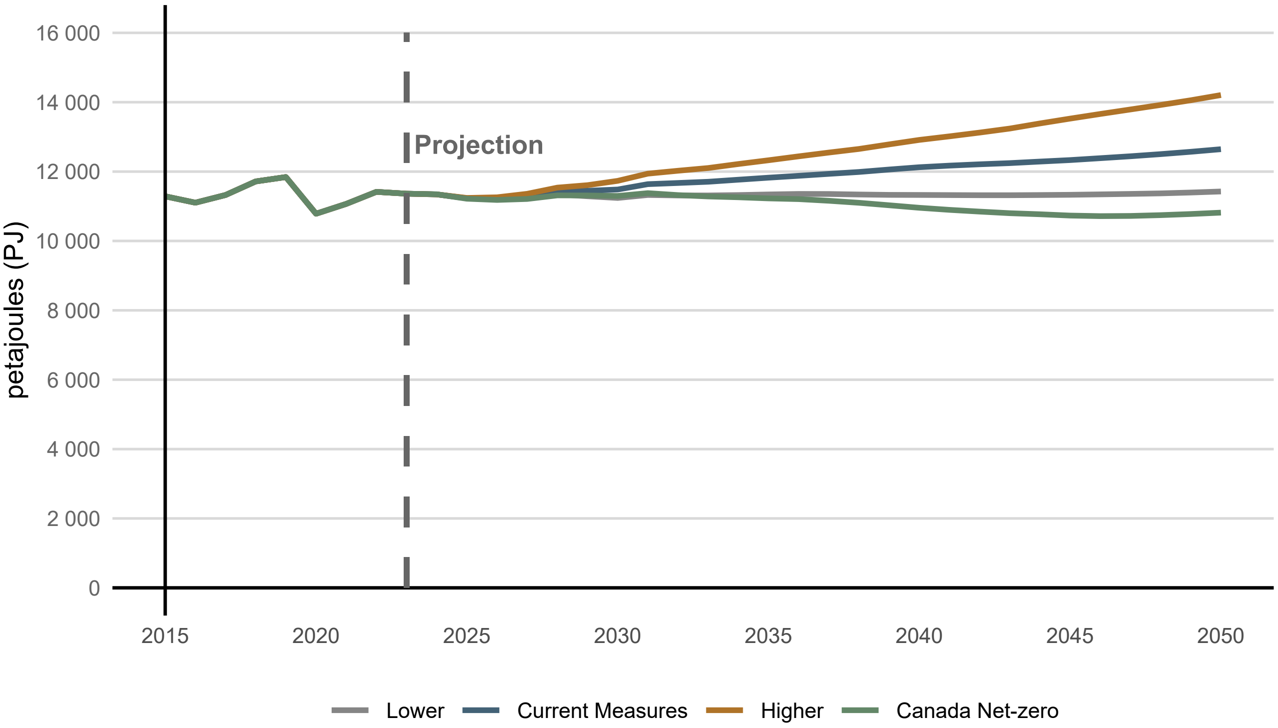
[12] Historical energy demand data is sourced primarily from Statistics Canada’s Report on Energy Supply and Demand in Canada. This data is supplemented with additional details from Environment and Climate Change Canada, Natural Resources Canada, and various provincial data sources.

[13] Primary demand is the total energy used in Canada, including energy to produce electricity and hydrogen. Our projections for primary demand in all four scenarios are available in our Data Appendix and Open Government tables. Primary and secondary demand are similar, but primary demand will be somewhat higher due to the energy value lost in converting primary energy sources into electricity or hydrogen. Primary demand also includes energy sources that are used in generating electricity, such as hydro and nuclear.

[14] In this report, demand does not necessarily equal domestic production. Differences between production and demand largely reflect net exports or imports.

[15] Unless otherwise stated, all monetary values are expressed in Canadian dollars (CAD).

R.1: Total end-use demand, all scenarios



Fossil fuels (including natural gas, natural gas liquids, refined petroleum products, and coal) currently make up the majority of end-use demand in Canada (over 75% in 2023), and their use in the future varies across the scenarios (Figure R.2). In the near-term, fossil fuel combustion falls. This is due to shifts towards biofuels and electricity, driven by policies such as Canada's Clean Fuels Regulations and the Electric Vehicle Availability Standard[16], as well as improving energy efficiency. Longer term economic growth, as well as oil and natural gas production trends (producing crude oil and natural gas is energy intensive), determine fossil fuel demand trends in the longer term. Canada Net-zero shows the largest amount of change in the energy mix, as increasing climate action drives down fossil fuel combustion. By 2050, some fossil fuel demand for combustion remains in Canada Net-zero and is either from processes equipped with CCUS (for example, by 2050 heavy industry sequesters 22 MT per year via CCUS, and the oil and natural gas sector sequesters 51 MT) or where emissions are offset by other sectors. Emissions are offset where it is more costly to adopt clean fuels and/or it takes longer for capital stocks to turnover.

Fossil fuels used for non-combustion purposes, such as petrochemical feedstocks, asphalt, and lubricants, grow in all scenarios. This implies that a greater share of fossil fuel demand goes towards non-combustion uses in the future. In 2050, the share of total fossil fuel demand used for non-combustion purposes is 22% in Current Measures and 33% in Canada Net-zero, compared to around 15% currently.

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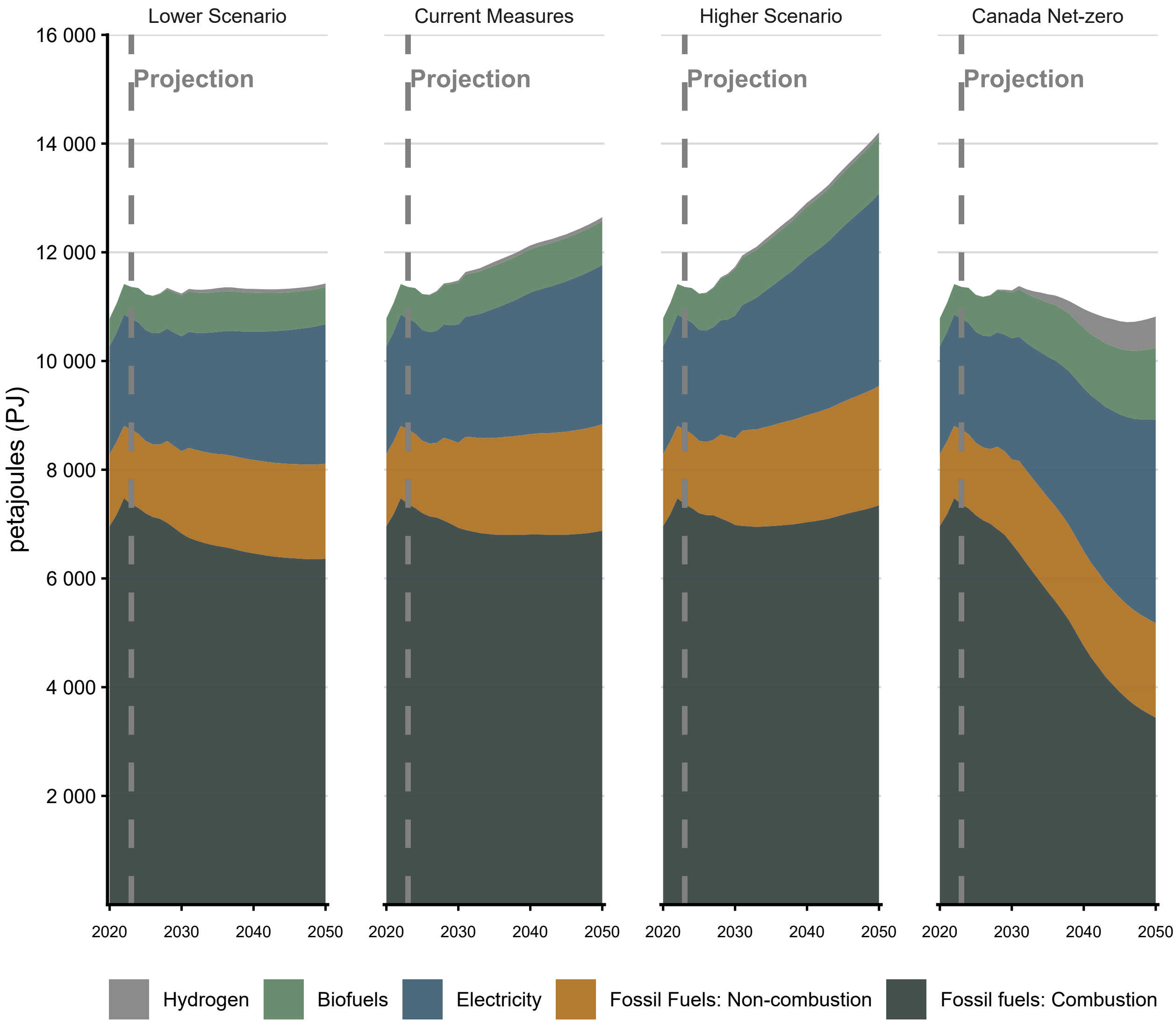
[16] As noted in the Scenarios and Assumptions chapter, the Government of Canada announced that it would repeal the Electric Vehicle Availability Standard in early February 2026, in favour of other policies to encourage EV adoption. Our modeling is based on policies that were in-place November 2025 and does not reflect these changes.

Across all four scenarios, electricity shows the largest percentage increase in demand from 2023 to 2050[17], ranging from 26% in the Lower scenario, 44% in Current Measures, 73% in the Higher scenario, and 84% in Canada Net-zero (Figure R.2). End-use biofuel[18] demand also grows in all four scenarios. Low and non-emitting hydrogen becomes a bigger part of the end-use mix in Canada Net-zero (production increases in all scenarios due to hydrogen produced for export, as discussed in the Hydrogen section later in this chapter).

Figure R.2: End-use demand by fuel, all scenarios



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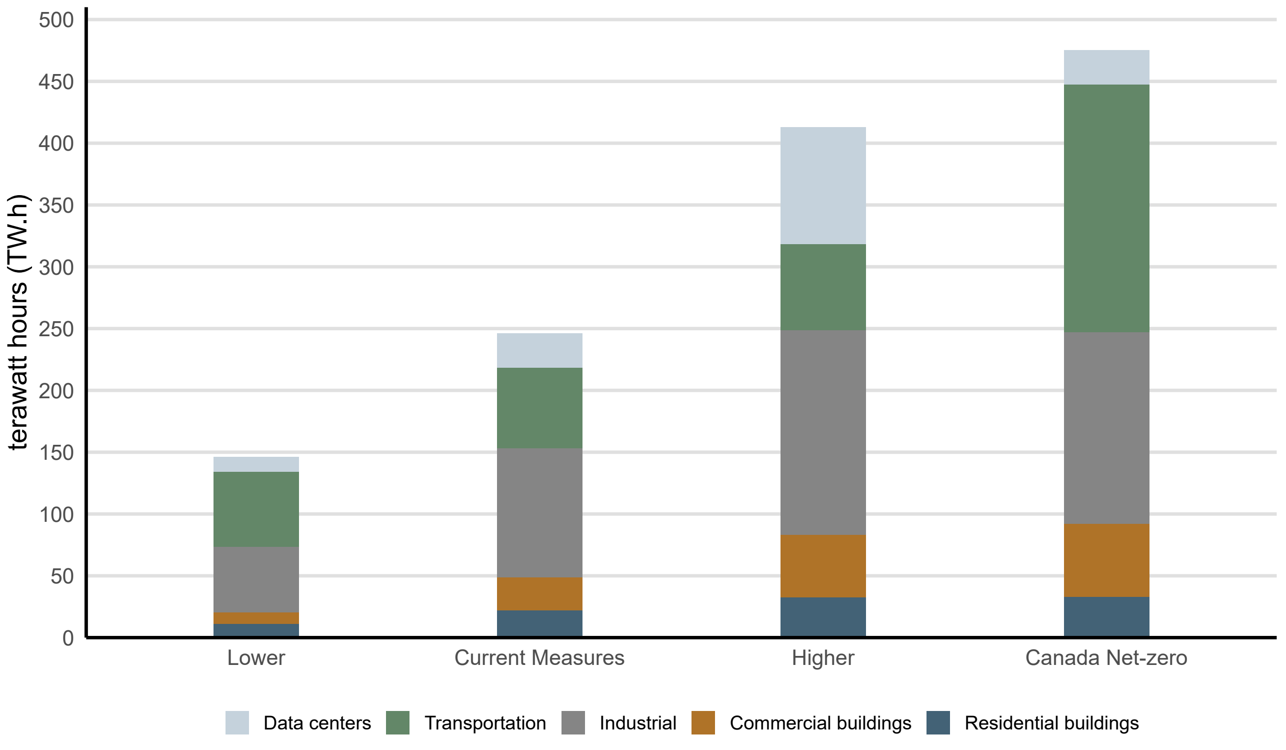
[17] Electricity used to produce hydrogen by electrolysis is included in the total electricity demand figure in the next section. It is not included in this figure to avoid double-counting with the hydrogen volumes.

[18] In this report, biofuels include liquid, gaseous, and solid fuels derived from biomass.

Growth in electricity demand varies across scenarios in terms of how much total electricity demand is added, and where the growth is coming from (Figure R.3). One of the key assumptions that influence electricity demand in our scenarios is data centre load growth. In the Higher scenario, data centre load growth makes up about a quarter, or 100 TWh, of the total projected end-use electricity demand growth. Electricity demand is also driven by economic activity. Commercial and industrial loads grow faster and slower in the Higher and Lower scenarios, respectively. Climate policy and clean technology adoption also play an important role, particularly through electrification of end uses and improvements in energy efficiency.

In the buildings sector, electricity demand is closely linked to total floorspace, as larger residential and commercial building stock requires more energy for lighting, heating, cooling, and appliances. As a result, differences in electricity demand across the Lower and Higher scenarios are largely driven by changes in floorspace. In contrast, electricity demand in Canada Net-zero grows faster than in the Higher scenario despite lower floorspace growth. While the Higher scenario has nearly 10% more residential and commercial floorspace by 2050 and smaller improvements in building shell efficiency, Canada Net-zero sees higher electricity demand due to a greater uptake of electrified technologies, such as heat pumps.

R.3: Growth in electricity demand, 2023 to 2050, by sector and scenario

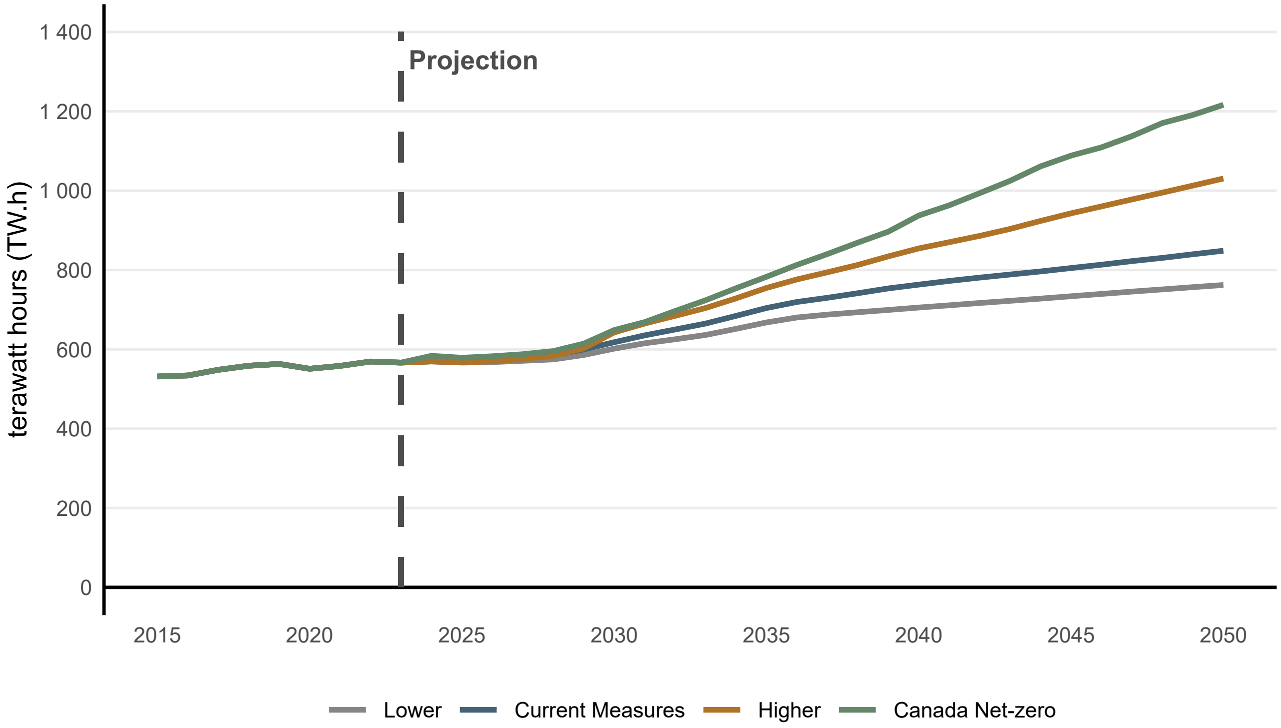


Electricity Capacity and Generation

We model the electricity capacity and generation necessary to meet the electricity needs outlined in the *Energy Demand* section, plus the electricity exported to the U.S. and electricity used to produce hydrogen. The analysis is done at an hourly level for each year of our projection, and accounts for any future changes in load patterns that follow from the demand trends, such as increased electrification of heating and transportation.

Canadian electricity demand—including end-use electricity described in the previous section, as well as electricity used to produce hydrogen—grows in all four scenarios, but with a large variation across them. The Lower scenario has the lowest demand, but still grows by 30% from 2023 to 2050, or a compound average annual growth of 1%, which is similar to recent historical levels. Current Measures increases by nearly 50% from 2023 to 2050, the Higher scenario by 80%, and Canada Net-zero by nearly 120%.

Figure R.4: Electricity demand, all scenarios



To meet these rising demands while maintaining adequate system reliability, installed electricity capacity (the total maximum power output of all generating facilities) increases as well (Figure R.5). In Current Measures, capacity increases from around 160 GW in 2023 to 310 GW in 2050. In 2050, capacity reaches 270 GW in the Lower scenario and 360 GW in the Higher scenario. Capacity rises to 400 GW by 2050 in Canada Net-zero.

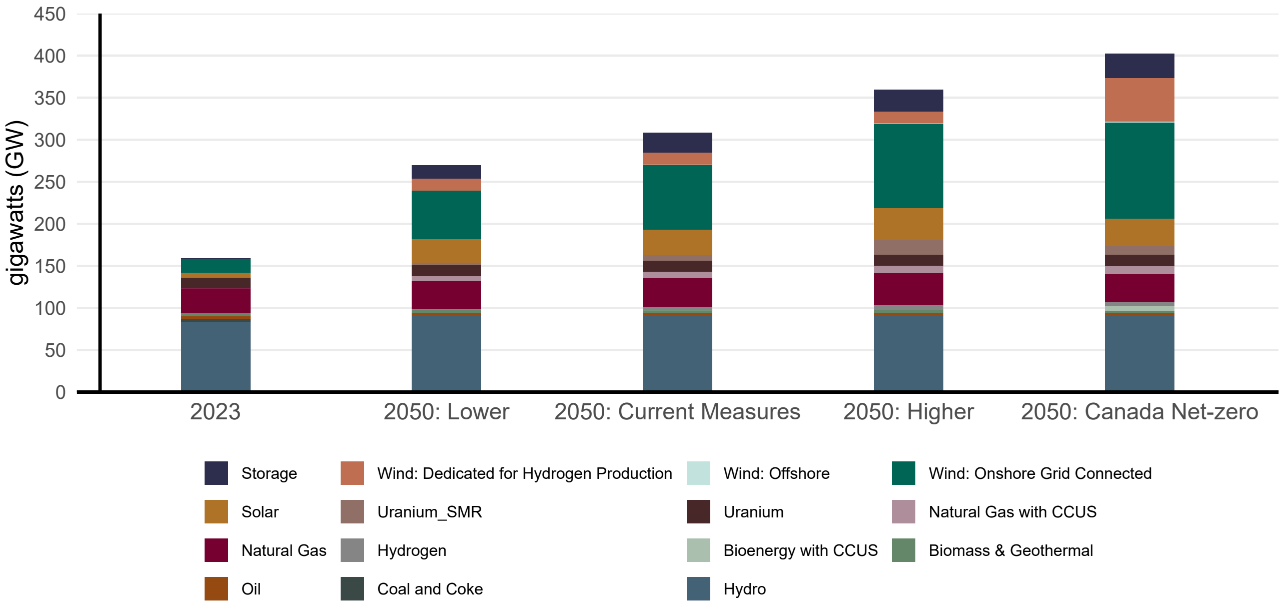
In all scenarios, wind energy makes up the largest capacity additions, with around 50 to 150 GW added from 2023 to 2050 across the scenarios. Most wind additions are from onshore wind that provides energy to the grid, while offshore wind plays a role in Atlantic Canada. We assume that most hydrogen produced via electrolysis is powered by dedicated wind generation, which adds to wind capacity in all scenarios. Depending on the scenario, around 20-30 GW of solar capacity and 15-23 GW of battery storage are added by 2050.

To ensure the electricity system can quickly respond to changes in electricity demand and variability in output from resources like wind and solar, our modeling shows significant additional capacity, including large amounts of natural gas with CCUS, nuclear (mostly small modular reactors), and hydroelectricity. In Canada Net-zero, emerging technologies such as bioenergy with CCUS—which allow for negative emissions—play a significant role. Natural gas capacity without CCUS grows in Current Measures and the Higher scenario and remains near current levels in the Lower scenario and Canada Net-zero.

From 2023 to 2050, total electricity generation ranges between an over 30% increase in the Lower scenario to more than doubling in Canada Net-zero. The generation mix also shifts, and by 2050 over 96% of generation comes from low or non-emitting technologies in all scenarios (Figure R.6). In all scenarios, the mix shifts to include much more wind electricity. Wind, which at 40 TWh accounted for 6.5% of generation in 2023, grows to 23% of the mix in the Lower scenario, 28% in Current Measures, 31% in the Higher scenario, and 40% in Canada Net-zero.

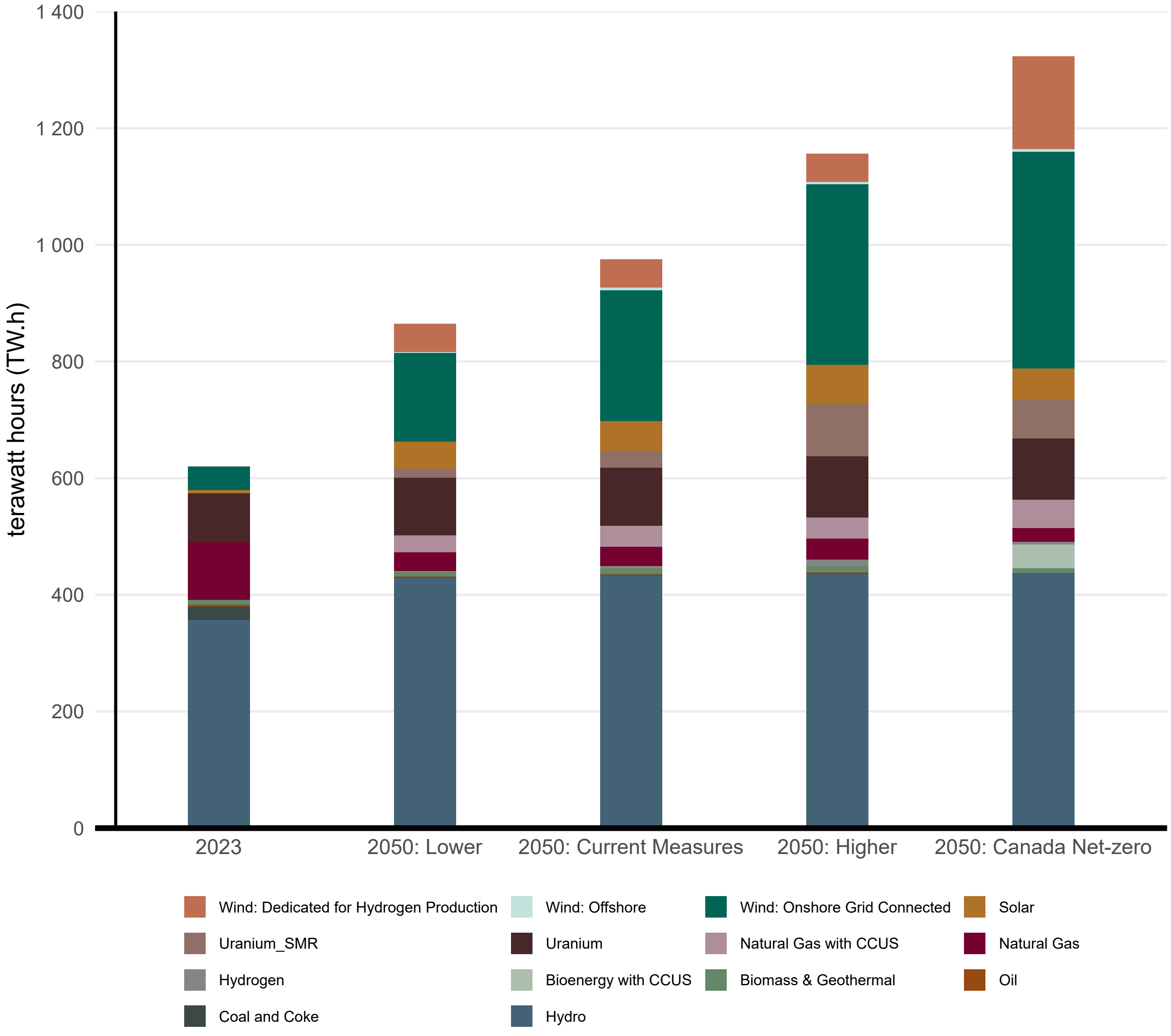
Natural gas generation without CCUS falls significantly in all scenarios, even though its capacity remains near or above current levels. In 2023, unabated natural gas accounted for 18% of capacity, and nearly 16% of generation. By 2050, unabated natural gas generation accounts for 11% of capacity in Current Measures, but only accounts for about 3% of generation as it is used sparingly. This signals a shift in role of natural gas from being used primarily for providing on-demand power to ensure system reliability.

Figure R.5: Electricity capacity by technology, 2023 and 2050, all scenarios



Solar generation increases from 7 TWh in 2023 to around 45 to 65 TWh across the scenarios, while hydroelectricity increases by over 50 TWh[19]. Emerging technologies, such as SMR, natural gas with CCUS, and bioenergy with CCUS, also play an important role, especially in Canada Net-zero. Bioenergy with CCUS is a negative emission technology, so its operation offsets emissions for the broader economy in addition to supplying electricity.

Figure R.6: Electricity generation by technology, 2023 and 2050, all scenarios



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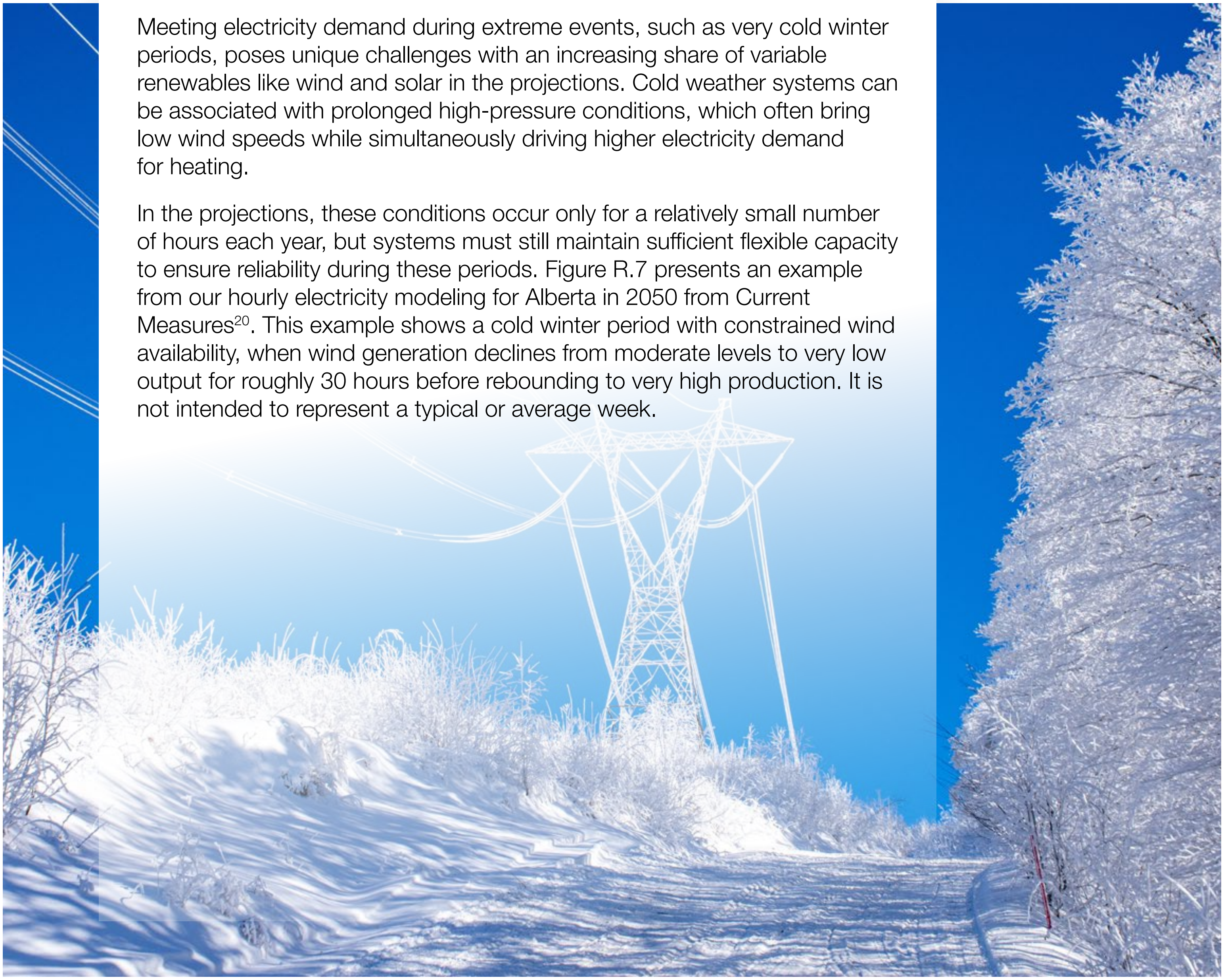
[19] Growth in hydroelectricity from 2023 ranges between 70-80 TWh across the scenarios, but this is due to 2023 having relatively low hydrogeneration due to low precipitation. In 2024, hydro generation rose 30 TWh over 2023 levels.

How do the grids of the future respond to extreme weather events?

Meeting electricity demand during extreme events, such as very cold winter periods, poses unique challenges with an increasing share of variable renewables like wind and solar in the projections. Cold weather systems can be associated with prolonged high-pressure conditions, which often bring low wind speeds while simultaneously driving higher electricity demand for heating.

In the projections, these conditions occur only for a relatively small number of hours each year, but systems must still maintain sufficient flexible capacity to ensure reliability during these periods. Figure R.7 presents an example from our hourly electricity modeling for Alberta in 2050 from Current Measures[20]. This example shows a cold winter period with constrained wind availability, when wind generation declines from moderate levels to very low output for roughly 30 hours before rebounding to very high production. It is not intended to represent a typical or average week.



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[20] The examples described in this chapter should be interpreted as illustrative of system behavior under the modeled conditions rather than a full reliability assessment. Such assessments typically analyze an exhaustive set of metrics that are beyond the scope of this analysis and are typically conducted by grid operators and reliability coordinators, like the North American Electric Reliability Corporation.

To further explore system resilience, Figure R.8 presents an illustrative stress case applied to the same winter period, but assuming even more severely constrained wind conditions. For Figure R.8, we simulate the grid operation for the same week as in Figure R.7, but with wind generation falling even further, to zero generation and remaining at zero for five days.

Figure R.7: Example of hourly winter electricity supply and demand during a week with a short period of low wind generation in Alberta (as modeled in Current Measures, 2050)

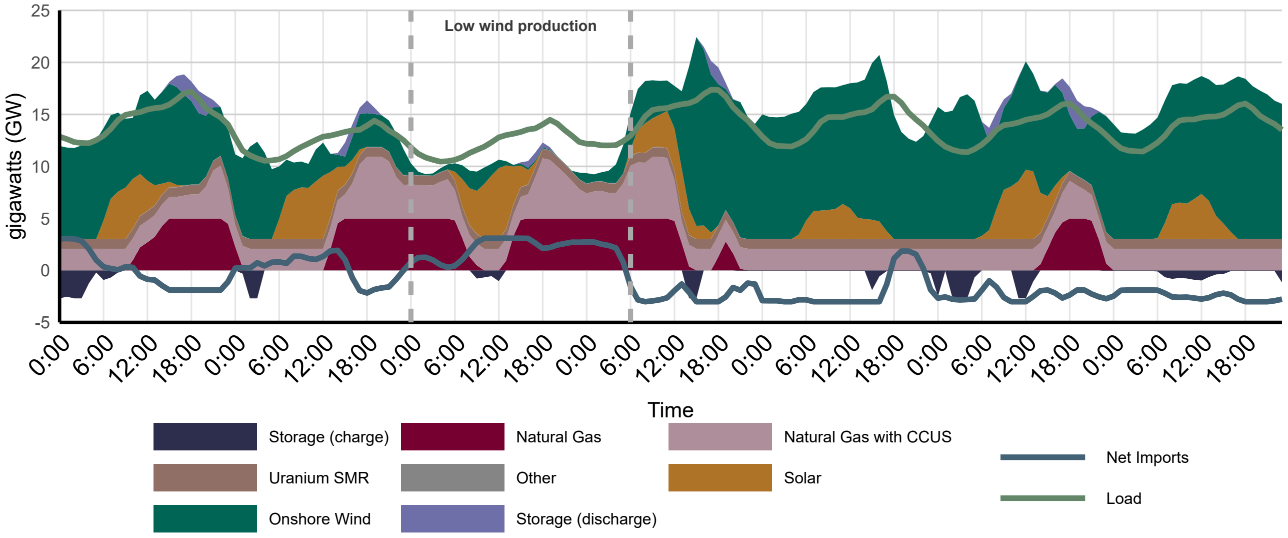
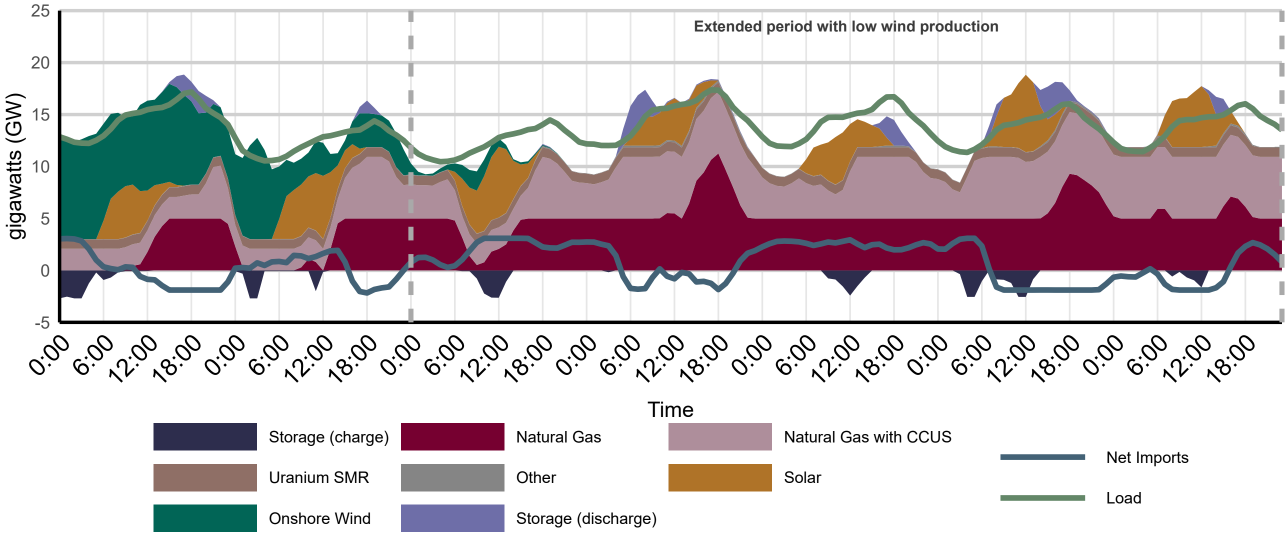


Figure R.8: Illustrative hourly winter electricity supply and demand during a week with an extended period of even lower wind generation than the case in Figure R.7 in Alberta



The first example (Figure R.7) shows that when wind output declines, other dispatchable resources increase output to maintain system balance. These resources are primarily natural gas units with and without CCUS. The example also shows that these dispatchable units generate much less during periods of high wind generation, when the province's generation is dominated by wind and Alberta is a net exporter of electricity.

The simulation with even lower wind (Figure R.8) shows Alberta relying even more heavily on dispatchable generation, storage, and imports to keep the system balanced. Over the simulated week, natural gas units supply about 67% of electricity. Electricity storage and interprovincial interties also play important roles: storage discharge increases by 37% relative to the same week with less extreme conditions (Figure R.7), and Alberta becomes a net importer of electricity from neighbouring provinces, using interties as a source of system flexibility to manage tight supply conditions.

The Clean Electricity Regulations set annual emission limits on the CO_2 emissions of fossil fuel generators, and those limits fall to zero in 2050. However, as shown in Figure R.7 and R.8, there is still some unabated natural gas generation in 2050, meaning some direct emissions do occur in this example. This is possible because the Clean Electricity Regulations include compliance flexibility, including the use of offsets, that allow fossil fuel generators to operate for a limited number of hours in 2050 and beyond. These are reflected in the modeled results discussed here.

These examples are based on weather patterns from one historical example year. In practice, extreme cold conditions can vary across years, and some rare events may lead to higher demand simultaneously in multiple provinces, reducing the availability of imports, which play a role in balancing the grid in the examples above. If interprovincial imports are unavailable, other options would need to be utilized. Importantly, our electricity supply modeling does not include large-scale demand-side management (DSM) programs and technologies that can reduce peak load and reduce grid stress. Examples include managed EV charging, time-of-use pricing, and automated demand response for commercial and industrial loads. There is considerable potential for DSM to grow as a grid management tool over the coming decades. As a result, incorporating DSM could further reduce the generation and import requirements compared to what is shown in these examples.

Over time, as wind and solar generation expand, the importance of system flexibility—through back-up dispatchable generation, electricity storage, interprovincial trade, and potentially DSM—continues to grow. This is especially evident in the Canada Net-zero and Higher scenarios, which feature the highest shares of variable renewables. These results highlight the growing role of planning for rare but high-impact extreme weather events.

Interprovincial transmission lines and trade

Across all scenarios, interprovincial trade enabled by transmission interties plays a growing role in balancing variations in electricity supply and demand across provincial systems[21]. By 2050, total interprovincial transmission capacity increases by roughly 70% in all scenarios, with expansions along nearly all interprovincial corridors.

Interties facilitate transfers between neighbouring provinces under two distinct conditions. First, they help manage periods of low demand or high variable generation (e.g., high wind generation) by enabling provinces with surplus electricity to export to neighbours. Second, they contribute to system balancing during episodes of provincial electricity supply stress, including rare but high impact extreme weather events such as the one described in the previous section “How do the grids of the future respond to extreme weather events?”

In the projections, the total annual interprovincial electricity inflows (and outflows) more than double, rising from 55 TWh in 2023 to 137 TWh by 2050 in the Current Measures scenario, and reaching as high as 140 TWh in the Canada Net zero scenario. Most annual flows occur during more common low demand or high variable generation hours, while contributions during infrequent extreme events remain smaller in volume but essential for reliability.

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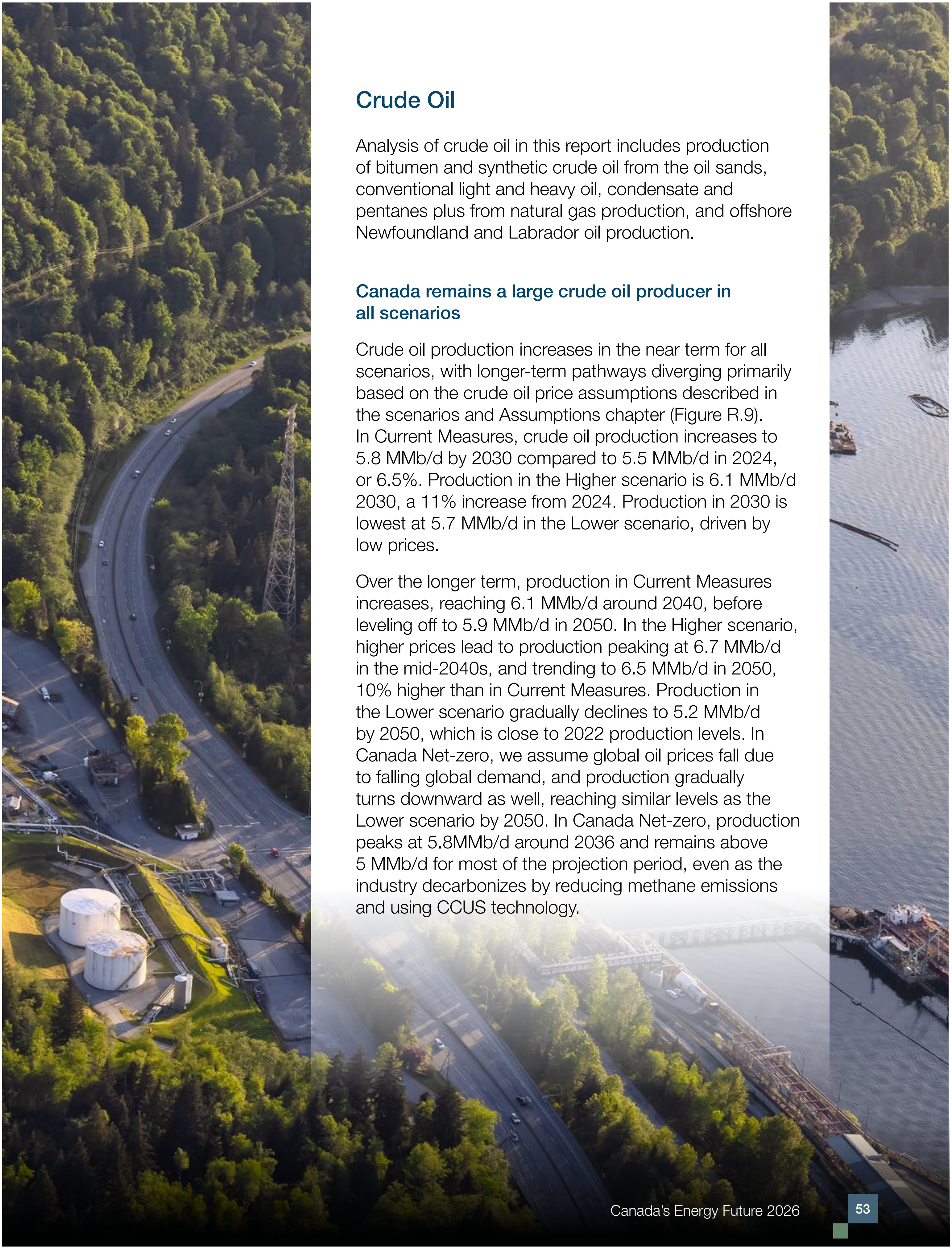
[21] The construction of new electricity facilities, including interprovincial transfer capacity, is based on a model that simulates the electricity system that meets demand at the lowest possible total system cost. As a result, most new transmission capacity in the scenarios is determined by the model itself. Transmission projects that utilities are already planning are included as fixed assumptions, and transfer capacity between Canada and the U.S. is held constant over the projection period.



Crude Oil

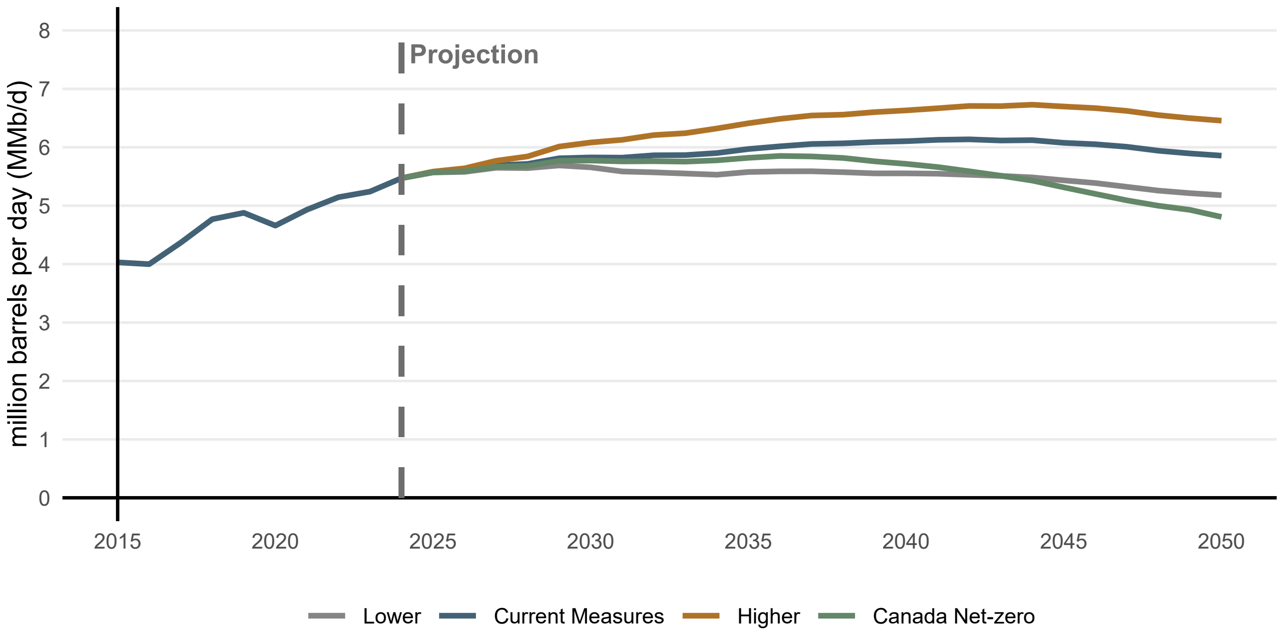
Analysis of crude oil in this report includes production of bitumen and synthetic crude oil from the oil sands, conventional light and heavy oil, condensate and pentanes plus from natural gas production, and offshore Newfoundland and Labrador oil production.

Canada remains a large crude oil producer in all scenarios

Crude oil production increases in the near term for all scenarios, with longer-term pathways diverging primarily based on the crude oil price assumptions described in the scenarios and Assumptions chapter (Figure R.9). In Current Measures, crude oil production increases to 5.8 MMb/d by 2030 compared to 5.5 MMb/d in 2024, or 6.5%. Production in the Higher scenario is 6.1 MMb/d 2030, a 11% increase from 2024. Production in 2030 is lowest at 5.7 MMb/d in the Lower scenario, driven by low prices.

Over the longer term, production in Current Measures increases, reaching 6.1 MMb/d around 2040, before leveling off to 5.9 MMb/d in 2050. In the Higher scenario, higher prices lead to production peaking at 6.7 MMb/d in the mid-2040s, and trending to 6.5 MMb/d in 2050, 10% higher than in Current Measures. Production in the Lower scenario gradually declines to 5.2 MMb/d by 2050, which is close to 2022 production levels. In Canada Net-zero, we assume global oil prices fall due to falling global demand, and production gradually turns downward as well, reaching similar levels as the Lower scenario by 2050. In Canada Net-zero, production peaks at 5.8MMb/d around 2036 and remains above 5 MMb/d for most of the projection period, even as the industry decarbonizes by reducing methane emissions and using CCUS technology.

Figure R.9: Total crude oil production by scenario



Canadian oil production in Current Measures continues to be dominated by the oil sands, as shown in Figure R.10. Total oil sands production (broken out as Mined Bitumen and In Situ Bitumen in Figure R.10) continues to grow to 2050 in Current Measures, reaching 4.1 MMb/d by 2050. The plateauing and longer-term production declines in total crude oil production are attributed to declines in conventional heavy and light production. Offshore oil production remains relatively stable to the mid-2040s and then declines as aging facilities come offline.

Oil sands production makes up the majority of production in all scenarios (Figure R.11). In 2050, conventional light, heavy, and offshore production is lower than 2024 levels. In the Higher scenario, production is over 6.5 MMb/d in 2050, largely driven by a 900 Mb/d increase in oil sands production from 2024 levels. Even in the lower production scenarios, oil sands production remains near 2024 levels by 2050. Longer term declines in the scenarios are driven by declining production in conventional light and heavy oil, to varying degrees.

Figure R.10: Oil production by type, Current Measures

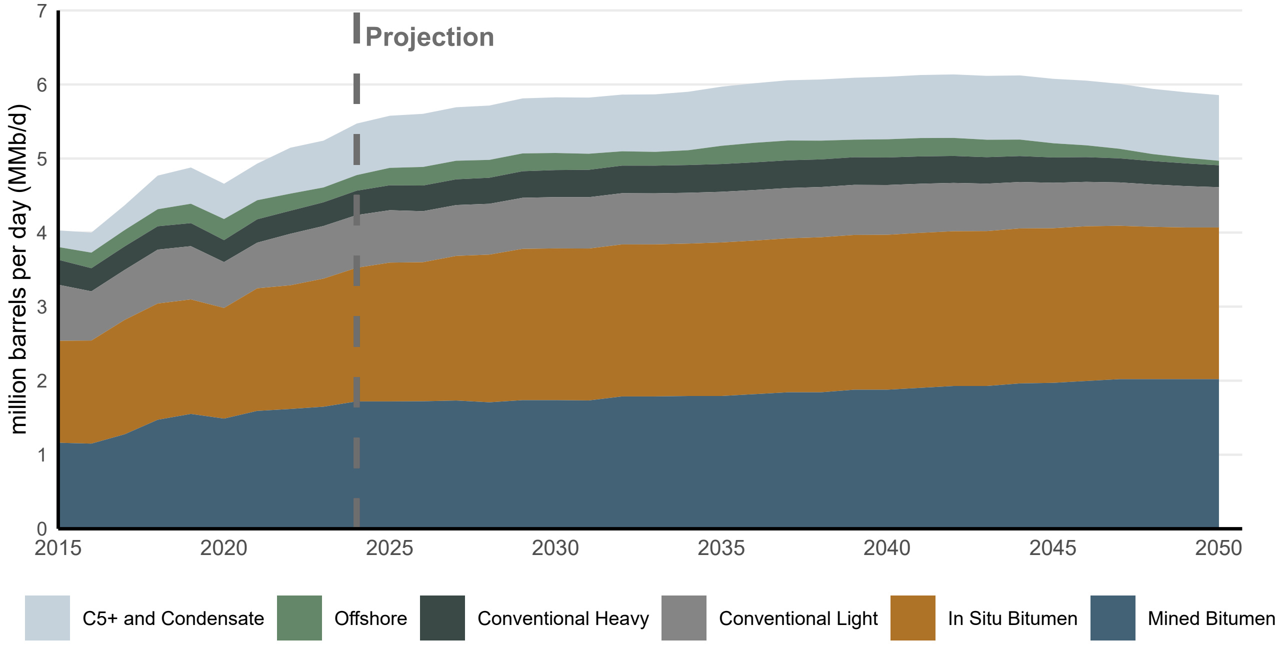
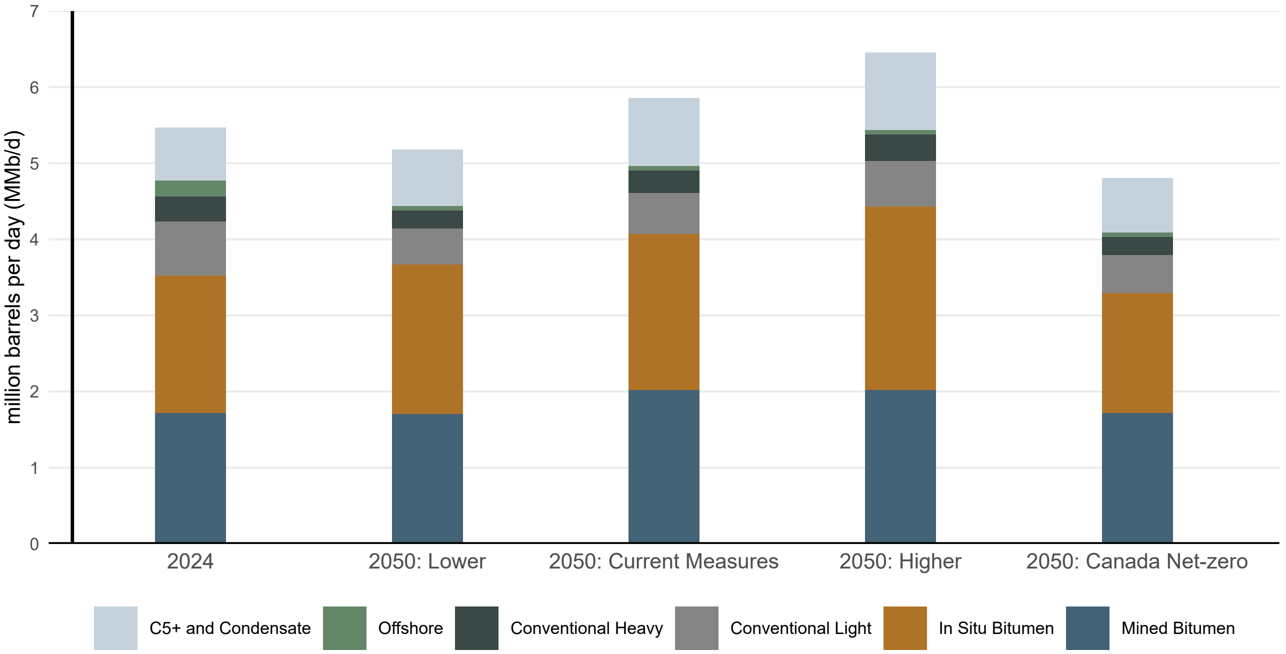


Figure R.11: Oil production by type, 2024 vs 2050, all scenarios



What if CCUS costs for oil sands production are higher than what is assumed in Canada Net-zero?

Technology costs are a major uncertainty in long-term energy outlooks. In Canada Net-zero, oil production, which is largely driven by the oil sands, declines from today but remains relatively close to recent historical volumes. A key reason for this relatively strong production in a net-zero context is the availability of technological pathways to lower emissions, coupled with an assumed oil price that is greater than $60 per barrel (2025 US$[22]) for most projection years. For the oil sands, much of this hinges on the economics of deploying CCUS at scale. In short, the less expensive it is to adopt new technology, the more likely it is to be adopted. This allows producers to continue operating while reducing emissions in line with an economy-wide transition to net-zero.

Our CCUS assumptions play an important role in how much of the technology is adopted in our scenarios, and therefore on our overall oil production projections. Because CCUS remains an emerging technology with highly uncertain future costs, we developed a High Cost CCUS sensitivity case. This sensitivity case starts with the same assumptions as Canada Net-zero but applies significantly higher CCUS costs to oil sands operations and re-runs the oil sands production model. It provides an illustrative view of how production might evolve in such a scenario if CCUS is more expensive for the oil sands sector.

Table R.1 compares CCUS cost assumptions in Canada Net-zero and the High Cost CCUS sensitivity case. In the High Cost CCUS sensitivity case, CCUS costs are assumed to be about double the values we assume in Canada Net-zero.

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[22] Oil prices are expressed in US$, consistent with international oil market benchmarks, unless otherwise stated.

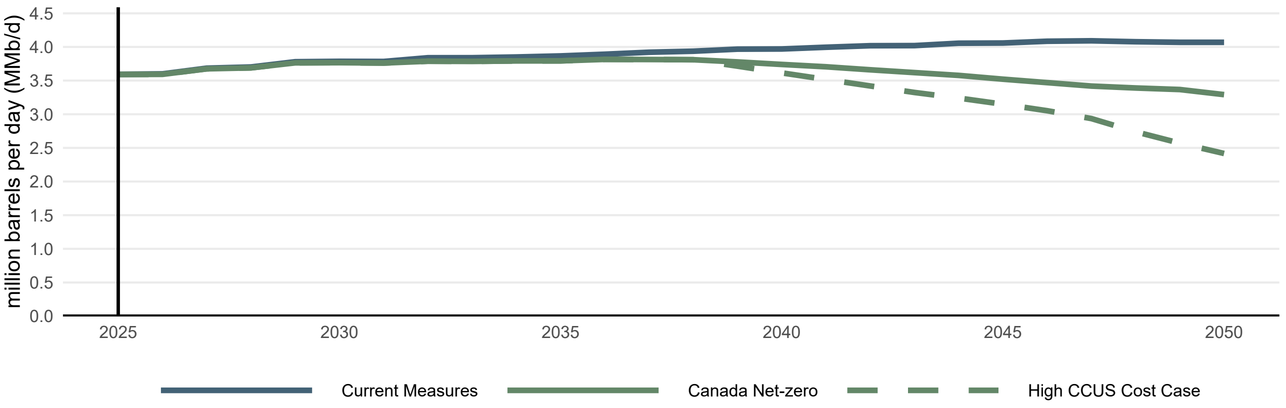
Alberta Carbon Conversion Technology Centre, Photo credit: InnoTech Alberta

Table R.1: Lifecycle cost of CCUS facilities in the oil sands (construction, operation, and transportation)

	2030			2050		
	2025$ CAD per tonne (before tax credits)					
CCUS facilities in:	**Steam Generation**	**Cogeneration**	**Upgrading**	**Steam Generation**	**Cogeneration**	**Upgrading**
Canada Net-zero scenario	250	300	150	190	225	110
High CCUS Cost sensitivity case	500	600	300	300	450	240

In Canada Net-zero, oil sands production is 3.3 MMb/d by 2050, with 40 MT of carbon dioxide (CO_2) stored with CCUS. In the High CCUS Cost sensitivity case, 25% less CCUS is used in the sector, leading to 30 MT of CO_2 stored in 2050. Faced with higher CCUS costs, our model shows oil sands producers increasingly choosing to shut down production instead of applying more costly CCUS or other, more expensive decarbonization options. In the High CCUS Cost sensitivity case, oil sands production trends over 25% lower than Canada Net-zero by 2050 at 2.4 MMb/d (Figure R.12). By 2050, oil sands production in the High CCUS Cost sensitivity case is 40% lower than Current Measures.

Figure R.12: Oil sands production in Current Measures, Canada Net-zero, and the High CCUS Cost sensitivity case



This sensitivity analysis is not a fully modeled scenario. Relatively higher costs of CCUS in the oil sands, and changes in production and technology trends, could have implications throughout the economy and energy system which are not covered in this narrow sensitivity analysis.[23] The High CCUS Cost sensitivity case is valuable in highlighting the importance and sensitivity of our underlying assumptions on the results, and illustrates how sensitive outcomes can be on individual variables.

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[23] For example, 2050 CCUS costs for Steam Generation and Cogeneration in the High CCUS Cost sensitivity case are more expensive than direct air capture (see Appendix 2 for cost assumptions).

Accounting for producer and investor behaviour in production outlooks

Developing the Canada's Energy Future oil and natural gas production outlooks involves integrating the stated assumptions of each scenario with other factors that are less well defined but play an important role in building the projections. These factors are generally related to corporate behavior and external uncertainty, and can interact with the effects of other assumptions, like high oil prices, to influence production growth. Should producer and investor behaviour change in the future, production growth could be meaningfully higher or lower than the scenarios in this report project, even under similar price assumptions. Some of the less discussed, but important complexities, of production modeling include:

- **Capital allocation:** Investors require a return on their investment. Following significant growth in oil sands, shale oil, tight oil, and natural gas production in the early 2010's, investors have required oil and gas companies to return a higher portion of their profits to shareholders. This, along with companies looking to more stringently manage cashflow and debt levels, has left less capital available to grow production. This is not unique to Canada; U.S. producers have experienced similar changes. The projections in this report are premised on producers continuing to prioritize returning cash to shareholders over growing production. Capital expenditures in the oil and gas sector grow from $50 billion in 2025 to a peak of $57 billion in Current Measures and $61 billion in the Higher scenario by 2039; by comparison, these capital expenditures reached a historic high of $106 billion in 2014 (all values in $2025 Canadian dollars). Should capital allocation priorities change so that more capital is put towards growth, other oil sands projects could advance. According to the Alberta Energy Regulator, there are 3.5 million barrels per day of greenfield oil sands projects and expansions to existing oil sands projects which have either received, or applied for, regulatory approval.

- **Pipeline capacity:** This report assumes there will be no physical constraints moving crude oil to export markets—scenarios hold oil price differentials (WTI-WCS) constant at $2025 12.50 per barrel throughout the projection. However, producers and investors have experienced periods when insufficient pipeline capacity led to western Canadian crude selling at large discounts, like in December 2018 when differentials exceeded $40 per barrel. In practice, this has likely led to some apprehension about deciding to significantly grow production. Because the projections in this report are premised on companies generally continuing to behave as they have in recent years, the projections may indirectly reflect such apprehension. Company behaviour may change if their expectations about future pipeline capacity change. For additional discussion on Western Canadian export infrastructure, see the *Canada's Energy Security, Self Sufficiency and Trade Diversification* chapter.
- **Commodity prices:** Commodity prices are an important assumption in the scenarios contained in this report and are fixed at the beginning of the modeling process. Our models assume companies have imperfect foresight of oil and natural gas prices. Specifically, companies in our models make an annual investment based on the prices of that year, while assuming prices do not change in subsequent years. Decisions are modeled this way because nobody can say with high certainty what oil and natural gas demand will look like in the future. Should our price assumptions not align with realized and anticipated prices, actual production over time may look very different than the values in the scenarios.
- **Policies:** This report assumes producers have knowledge of which policies will be implemented and their future stringencies. However, real world producers and investors must consider uncertainty and are influenced by expectations of whether new policies will be enacted or existing ones changed. As noted above, the projections in this report are premised on companies generally behaving as they have in recent years. Therefore, to the extent investments in recent years have been constrained by policy uncertainty, the projections may indirectly reflect such constraints.

New, large-scale oil projects, especially in the oil sands, can take several years to build and have life spans measured in decades, making them sensitive to uncertainties and driving unexpected results if only considering headline assumptions like commodity prices. As with any assumption made in this type of study, future producer and investor behaviour could once again change and drive oil production results materially higher or lower than shown across the Canada's Energy Future scenarios.

Natural Gas

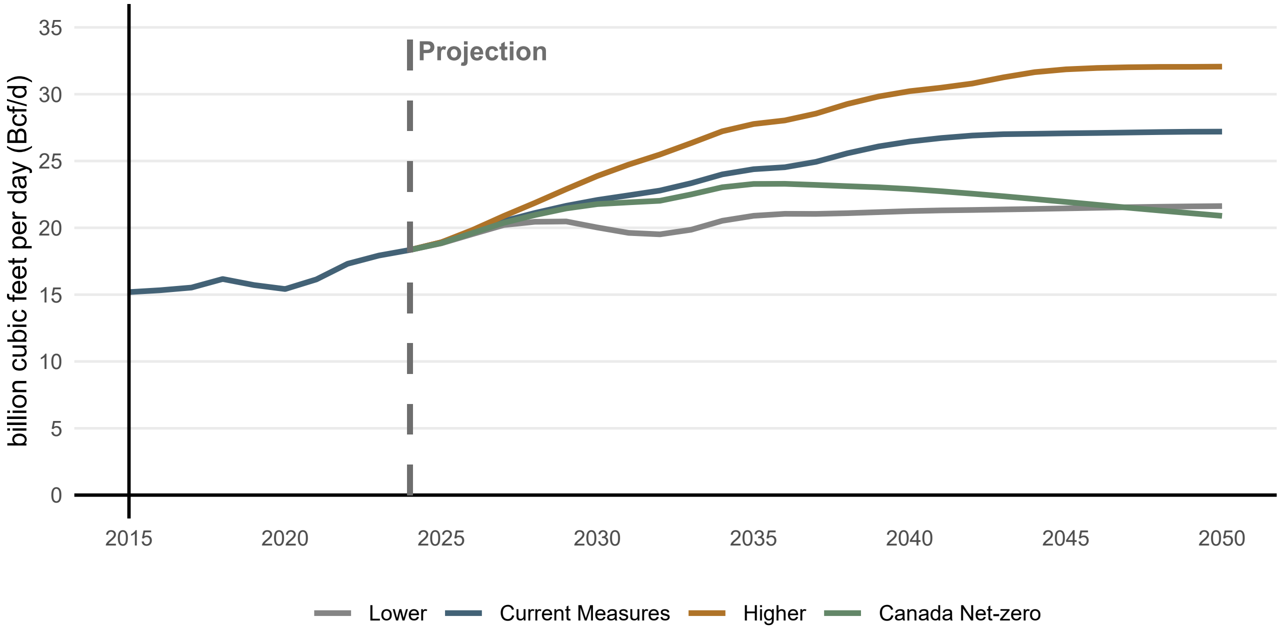
Key drivers for natural gas production include North American natural gas prices, which determine the profitability of drilling new wells, and assumptions on LNG exports, described in the Scenarios and Assumptions chapter.

Natural gas production grows in all scenarios

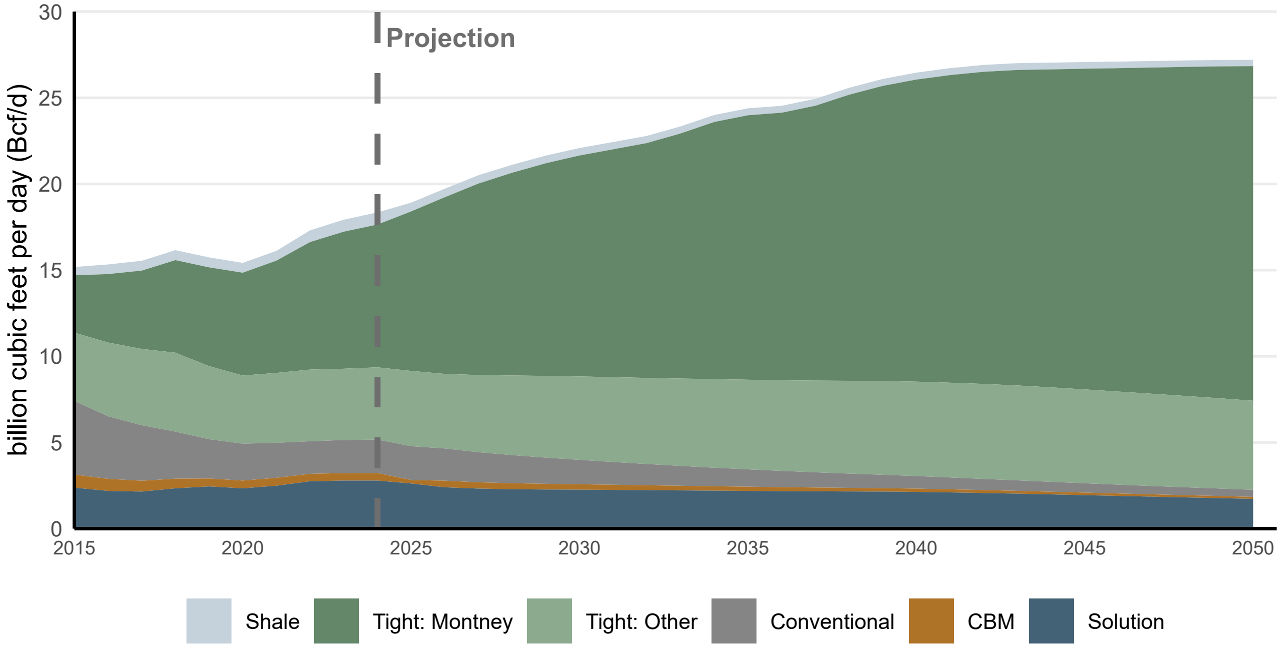
In recent years, Canadian natural gas production increased rapidly from 15.7 Bcf/d in 2019 to a record high of 18.3 Bcf/d in 2024. Growth continues in all our scenarios, to varying degrees (Figure R.13). In 2035, production ranges between 2 to 9 Bcf/d higher than 2024 levels. Over the longer term, Current Measures and the Higher scenarios trend to 27 Bcf/d and 32 Bcf/d in 2050, respectively. Growth is limited in the Lower scenario and Canada Net-zero, which eventually decline to around 21 Bcf/d in 2050, which is still higher than 2024 levels.

Figure R.14 shows annual natural gas production in Current Measures, by type, over the projection period. Current Measures natural gas production continues the upward trend of producing mostly tight gas—gas produced from organic-rich shales or from low permeability sandstone, siltstone, limestone or dolostone reservoirs. Tight gas reservoirs typically require the combination of horizontal drilling and multi-stage hydraulic fracturing to achieve economic rates of production. Tight gas, which made up 28% of production in 2005 and 68% in 2024, accounts for 85% in 2035 and 90% in 2050. Tight gas production growth is largely centered in the Montney area in Northeast British Columbia and Northwest Alberta. Conventional, solution, and coal bed methane (CBM) decline to varying degrees in the long term. Figure R.15 shows that this trend happens in the Higher scenario, Lower scenario, and Canada Net-zero as well.

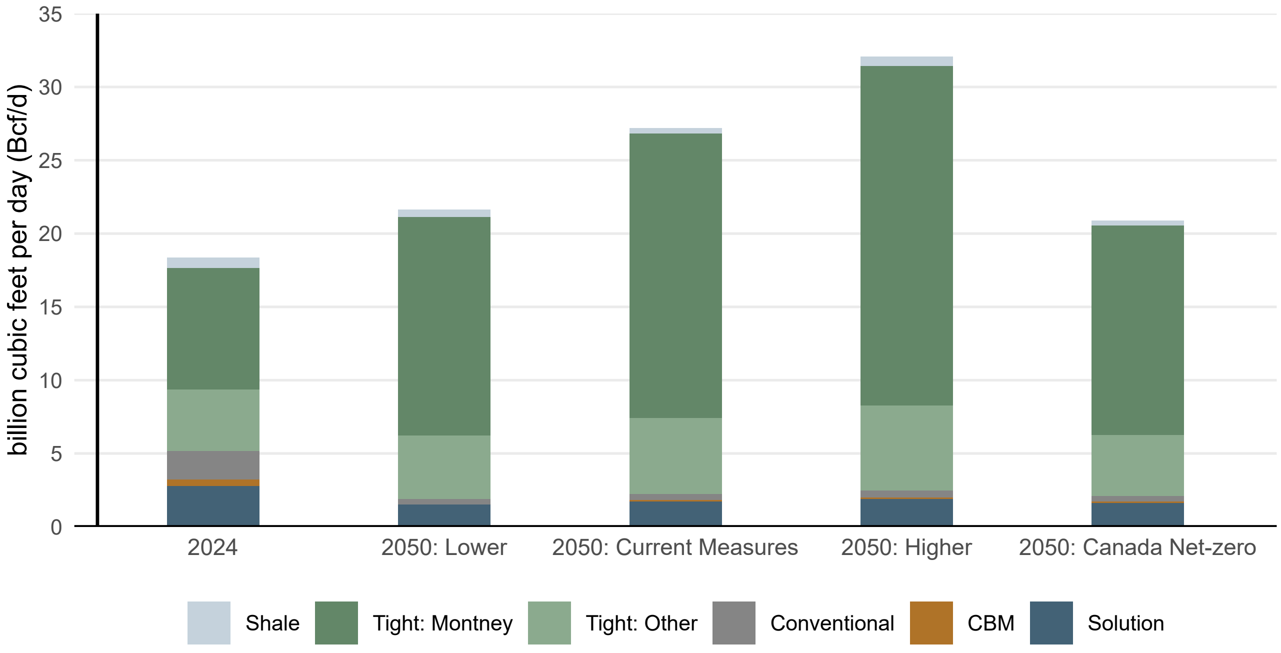
R.13: Total natural gas production in all scenarios



R.14: Natural gas production, Current Measures, by type



R.15: Natural gas production by type, 2024 vs 2050, all scenarios

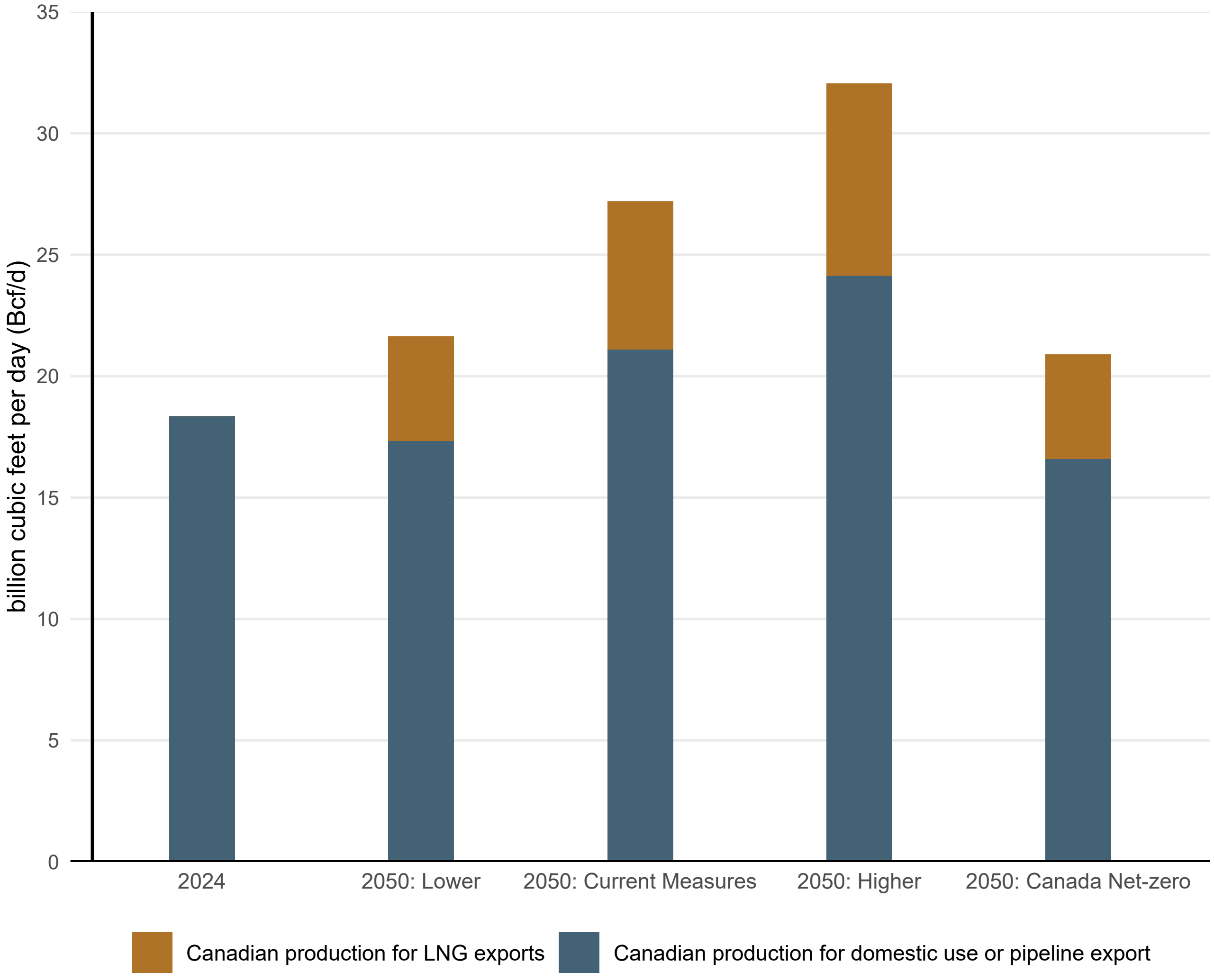


LNG exports as a key driver of natural gas production growth

LNG exports are a key driver of natural gas production growth. As noted in the Scenarios and Assumptions chapter, for the purpose of our projections, we assume 75% of gas that goes to LNG exports is dedicated production that only exists because of the LNG export volumes we assume in each scenario. We assume 75% is incremental production because some LNG exporters also own a large amount of gas resources in western Canada and have announced plans to produce gas from these corporate resources to at least partially supply their LNG exports, indicating this production may be less tied to North American gas prices. Further, some of these exporters are also large, global producers of natural gas and can potentially tap into a global pool of investment capital to fund development, capital that may not otherwise be available to domestic producers. We assume 25% comes from production that is driven by the price assumptions described in the Scenarios and Assumptions chapter, because the North American natural gas market is highly integrated, and it is likely that some gas going towards LNG would be purchased.

Figure R.16 breaks down total production in 2024 and 2050 between traditional markets for that production—domestic demand and pipeline exports—and exports from B.C. LNG projects. Overall, total production in all four scenarios in 2050 is higher than 2024 levels, with growth ranging from about 15%, 2024 to 2050, in the Lower scenario and Canada Net-zero, to nearly 50% in Current Measures, and nearly 75% in the Higher scenario. As shown in Figure R.16, much of this growth goes towards LNG exports. Natural gas going to traditional markets actually decreases in the Lower scenario and Canada Net-zero and increases by 15% in Current Measures and 32% in the Higher scenario. This represents a significant diversification of Canadian natural gas trade, from nearly all exports going to the U.S. via pipeline (in 2024, 8.64 Bcf/d of natural gas was exported by pipeline), to potentially over a third of exports with the ability to reach global markets via LNG in all scenarios by 2050[24].

Figure R.16: Natural gas production and disposition, 2024 and 2050, all scenarios



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[24] We do not make projections of actual import and export volumes. Depending on future import trends, the relative share of LNG in total Canadian natural gas exports could be higher or lower than this estimate.

Hydrogen

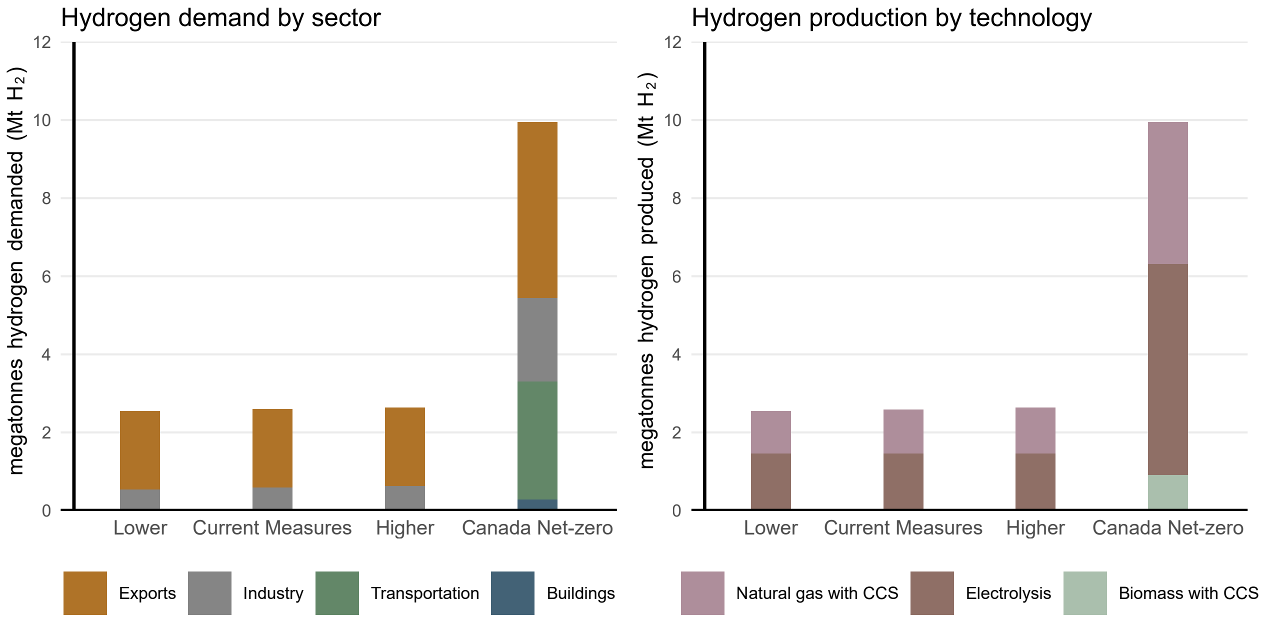
Hydrogen is an energy carrier that can be produced from a range of energy sources and used across multiple sectors. Our focus in this section is on incremental hydrogen demand and its production by methods that emit little or no CO_2.[25]

Hydrogen plays a key role in the Canada Net-zero scenario

Our projections for additional low and non-emitting hydrogen are driven by growth in domestic demand as well as hydrogen produced for export. Hydrogen remains a niche technology in Current Measures, and the Higher and Lower scenarios, mostly in the industrial sector. In Canada Net-zero, hydrogen makes up about 5% of the end-use demand mix by 2050. We assume hydrogen produced for export increases after 2030 in all scenarios, reaching 2 million tonnes (MT) by 2050 in Current Measures, the Higher, and Lower scenarios, and 4.5 MT by 2050 in Canada Net-zero.

Combined, total non-emitting or low-emissions hydrogen production reaches over 2.5 MT by 2050 in Current Measures, the Higher scenario, and the Lower scenario, and around 10 MT in Canada Net-zero. It is produced using electrolysis technology, with electricity from dedicated renewable electricity or increasingly non-emitting electricity from the grid, as well as natural gas with CCUS technology. Figure R.17 shows where hydrogen is used in 2050 (left chart) and how it is produced (right chart).

Figure R.17: Hydrogen demand by sector, and production by technology, all scenarios in 2050



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[25] Current hydrogen produced on-site in industrial facilities from natural gas is accounted for in our data as natural gas demand and excluded from the hydrogen projections shown in this section.

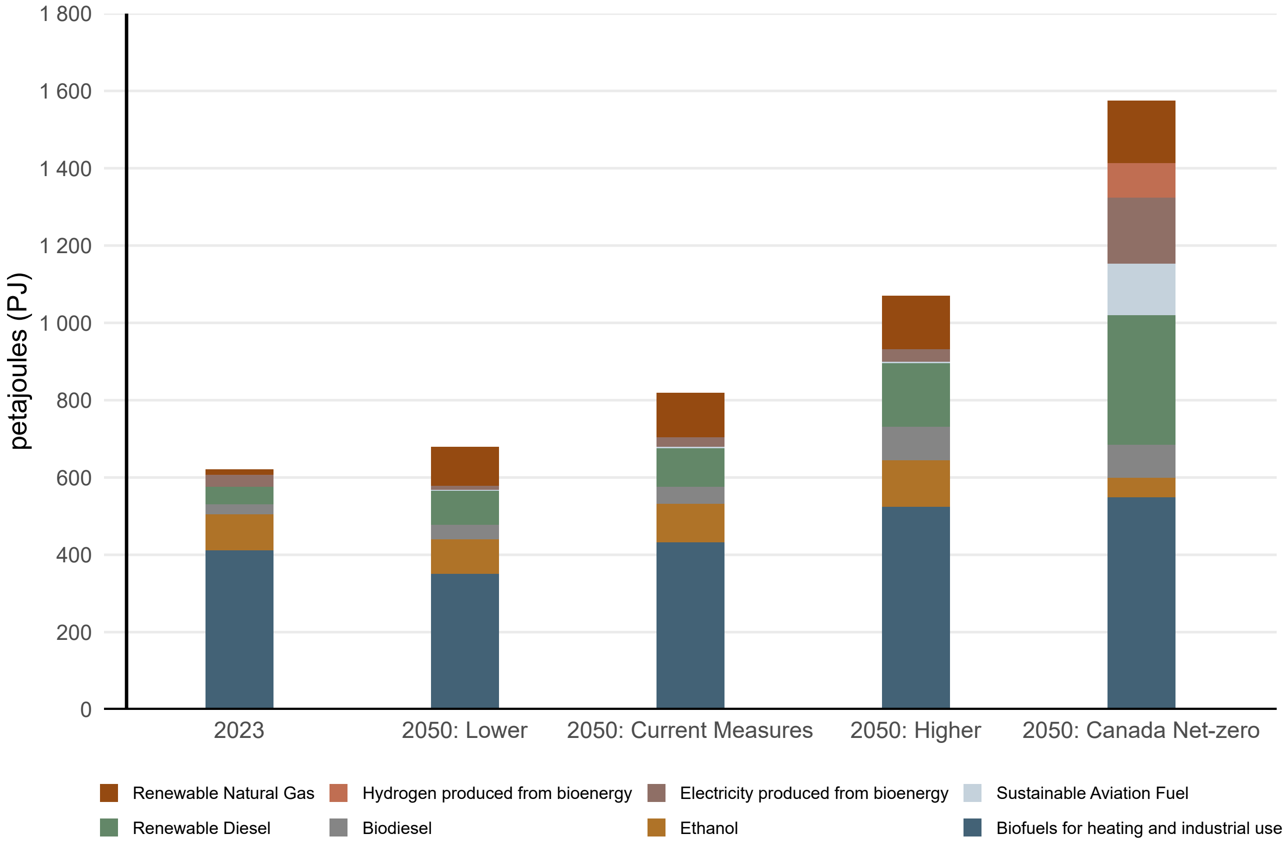
Bioenergy

Bioenergy is an important part of the energy mix, and it is currently used in a variety of sectors. In our projections, bioenergy adoption is based on technology, economic, and policy assumptions. We assess the feedstocks used to produce bioenergy based on several things, such as feedstock affordability, suitability, availability and cost, preprocessing requirements, required land use, and production technology.

Bioenergy use grows in all scenarios

Total end-use bioenergy demand, including electricity and hydrogen produced from bioenergy, increases by 10% in the Lower scenario, 32% in Current Measures, 73% in the Higher scenario, and around 150% in Canada Net-zero (Figure R.18). Policies such as Canada's Clean Fuels Regulations, and provincial initiatives like B.C. and Quebec's renewable natural gas blending mandates, are key factors in increasing bioenergy demands by 2050. In Canada Net-zero, increasing use of electricity and hydrogen produced with bioenergy (mostly with CCUS), as well as sustainable aviation fuel, become a large part of Canada's bioenergy use.

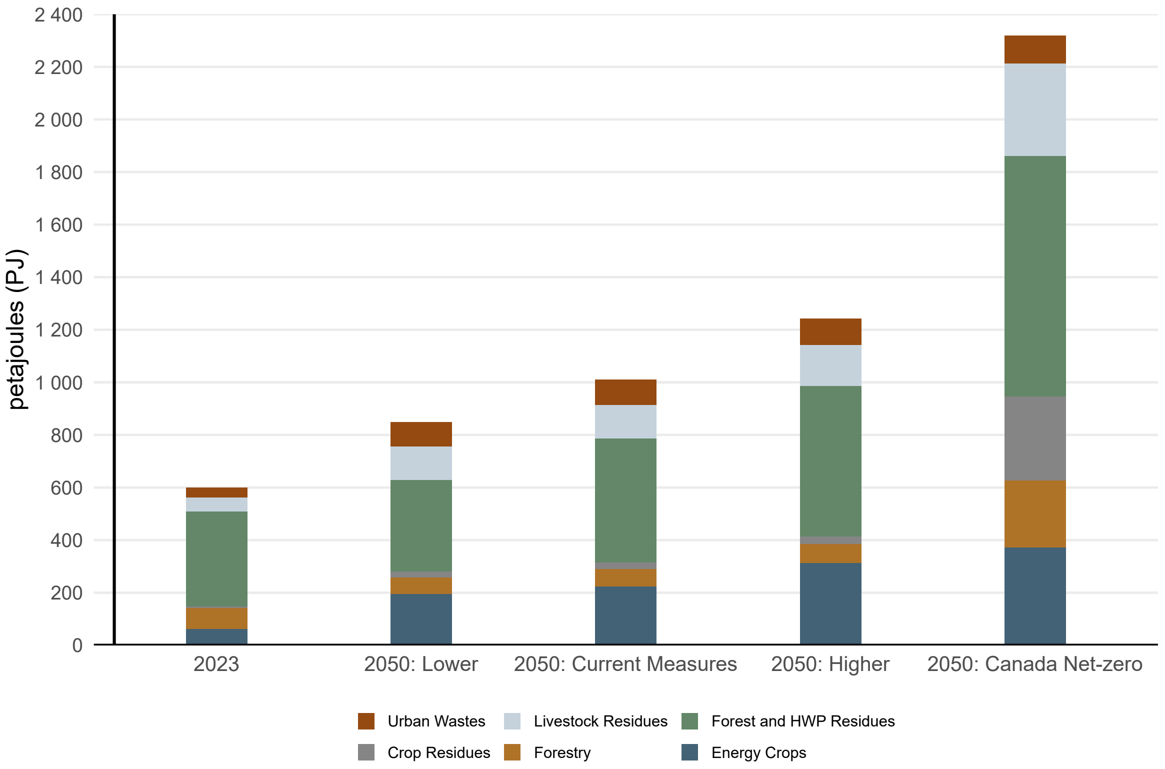
Figure R.18: End-use bioenergy demand by type, 2023 and 2050 for all scenarios



We project this growth in production will be met by a variety of different sources (Figure R.19). In 2023, most bioenergy production is sourced from forest and harvested wood products (HWP) residues. In Current Measures, forest and HWP residues[26], livestock residues, urban wastes, and energy crops (e.g., corn, canola and willow), make up most of the growth. The incremental feedstocks needed in Canada Net-zero come from a variety of different sources, including large increases in crop residues and forest and HWP residues. Imports also play a key role in meeting domestic bioenergy demand, mainly for liquid biofuels (e.g., ethanol, biodiesel, and renewable diesel) and RNG.

In Figure R.18, bioenergy demand by feedstock is shown in end-use terms. In comparison, R.19 expresses bioenergy as primary production. Trends may differ across the two charts because of conversion efficiencies. Processes like bioenergy with carbon capture and storage (BECCS), for example, have lower efficiency, requiring more petajoules of bioenergy feedstock to generate a petajoule of electricity.

Figure R.19: Primary bioenergy production by feedstock, 2023 and 2050



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[26] Forestry represents the wood produced as firewood and fuelwood. Forest and HWP residues refers to residues from harvesting, and forest and wood product manufacturing, as well as from forest fire mitigation activities, and unmerchantable wood from natural disturbances (i.e., forest fire & pest infestation).

Macroeconomics

Energy and the economy are deeply connected. Energy services support Canadians' quality of life, whereas fuels and electricity are essential for producing goods and services across the economy. Economic activity influences the quantity and types of energy used in Canada, whereas factors like exchange and interest rates impact energy markets. At the same time, our energy sector is both a significant consumer of energy and a major contributor to economic activity—driving trends in energy demand, investments, exports, and other factors. This section explains some of the key macroeconomic drivers in our projections.

Economic growth trends vary across the Canada's Energy Future 2026 scenarios

Key economic indicators vary across the four scenarios, as shown in Figure R.20. Current Measures shows moderate economic growth over the projection period, with population increasing by 0.7% per year, and real gross domestic product (GDP) increasing by 1.6% per year. The annual inflation rate is around 2.1%.

In the Higher scenario, we assume that key economic drivers grow faster. This, in combination with accelerated energy activity, leads to stronger economic growth, with real GDP growing by 2% per year, and a population growth rate of 0.9%.[27] An economy that is growing faster with higher energy prices, as we assume in the Higher scenario, also has moderately higher inflation compared to Current Measures, at 2.3% per year.

In the Lower scenario, our assumptions related to macroeconomic trends and energy prices lead to weaker economic growth compared to Current Measures. Real GDP grows by 1.2% per year, population grows 0.5% per year, and inflation is moderately lower than in Current Measures, at 2% per year.

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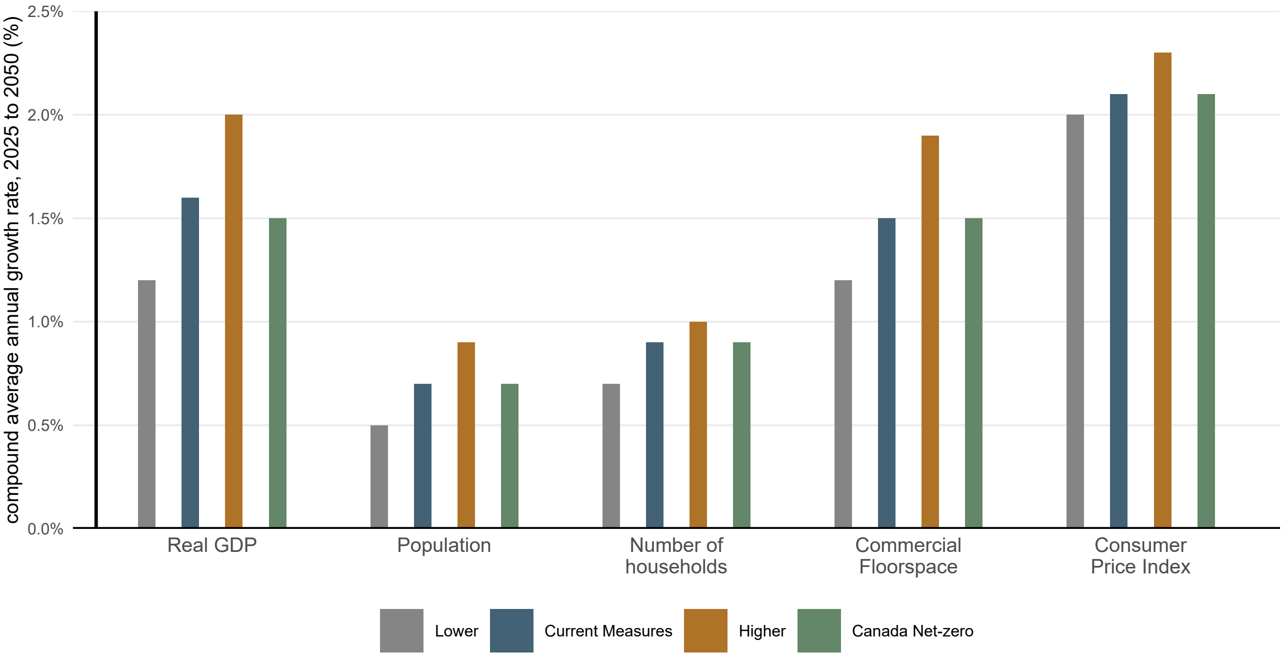
[27] Population levels adjust over the long term in the Higher and Lower scenarios, primarily via immigration, to meet the labour force requirements of relatively higher economic output levels.

By 2050, the Higher and Lower scenarios provide a significant range around Current Measures. In the Higher scenario, real GDP is 11%, or over 500 billion $2024 CAD higher than Current Measures, and Canada's population reaches 52 million, compared to 50 million in Current Measures. In the Lower scenario, real GDP is nearly 10%, or over 450 billion $2024 CAD lower than in Current Measures, and population is 47 million.

Canada Net-zero includes lower upstream oil and natural gas activity and stronger investment in clean technology (as discussed earlier in this chapter). Overall, this leads to economic growth trends that are marginally lower than Current Measures, and significantly higher than the Lower scenario.

The Canada U.S. exchange rate averages 0.75 CAD/US$ in Current Measures from 2025 to 2050, 0.76 CAD/US$ in the Higher scenario, 0.73 CAD/US$ in the Lower scenario, and 0.74 CAD/US$ in Canada Net-zero.

Figure R.20: Growth in key economic drivers, 2025 to 2050, all scenarios



Greenhouse gas (GHG) emissions

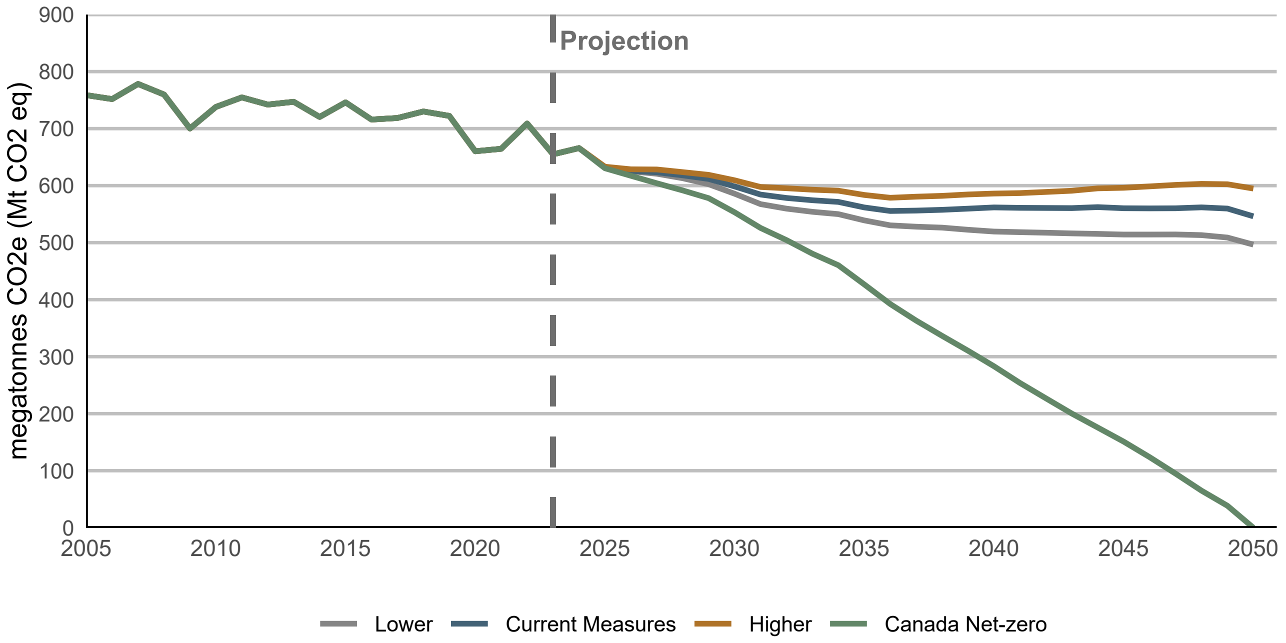
The greenhouse gas (GHG) emissions projections outlined in this chapter rely largely on the energy projections described previously in this chapter, as well as our estimates and assumptions about non-energy related GHG emissions from sources like agricultural waste and land-use changes.

The historical GHG emissions reported in this report are based on Canada's National Inventory Report. The latest historical emissions data available is from 2023. ECCC produces the official analysis of Canada's current emissions outlook and performance against its climate commitments.

GHGs decrease in all scenarios

GHG emissions fall throughout the projection period in all scenarios (Figure R.21). GHG emissions in Current Measures fall steadily in the early part of the projection and are 21% lower than 2005 levels (nearly 9% lower than 2023) in 2030, and 28% lower than 2005 levels (17% lower than 2023) in 2050. The Higher and Lower scenarios assume the same domestic climate policies as in Current Measures, so it follows that these scenarios have higher and lower emissions, respectively, due to different economic activity levels. In 2050, emissions in the Higher scenarios are 9% higher than Current Measures (and 22% lower than 2005 levels), while in the Lower scenario, emissions are 9% lower than Current Measures (and 35% lower than 2005 levels). Net emissions reach zero in 2050 in Canada Net-zero, which is not a projection, but a pre-determined constraint on this scenario.

Figure R.21: Net GHG emissions by scenario



The electricity sector leads the way in emission reductions

By 2050, most sectors have lower GHG emissions than in 2023 (Figure R.22). In Current Measures from 2023 to 2050, the largest declines come from electricity (-38 MT), oil and gas (-32 MT), and transportation (-30 MT). The electricity sector stands out, with over 90% lower emissions by 2050 in Current Measures, Higher, and Lower scenarios compared to the 2005 base year. This is a reduction on par, or above, what we see among other sectors even in Canada Net-zero.

In Canada Net-zero, all sectors follow the electricity sector and contribute to emissions reduction. The electricity sector reduces emissions even further and goes net-negative through the use of BECCS technology. In 2050, remaining emissions in agriculture, oil and natural gas, buildings, industry, transportation, and waste, are offset by negative emissions in the electricity sector[28], as well as land-use change and carbon removal, which includes reductions from nature-based solutions, direct air capture, and other carbon dioxide removal options.

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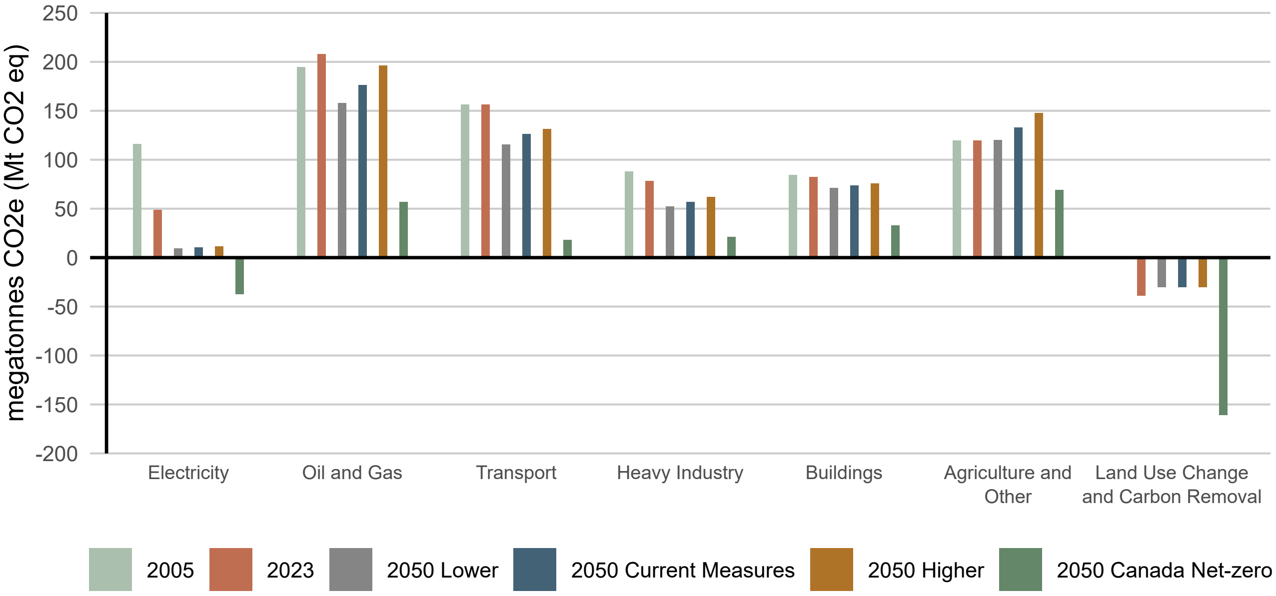
[28] Hydrogen production, which is included in “Agriculture and other” in Figure R.22, is also net negative, through the application of BECCS technology.

Figure R.22: GHG emissions by economic sector, 2005, 2023, and 2050, all scenarios



Analysis: Canada's Energy Security, Self Sufficiency and Trade Diversification

Introduction

Recent changes to longstanding geopolitical and trade relationships—including tariff volatility and trade regime uncertainty—have sharpened the focus of Canadians, policy makers, and businesses on the security, resiliency, and competitiveness of the Canadian energy system.

Energy security is a broad concept, generally it refers to having consistent and sufficient access to energy resources, fuels, and technologies that meet evolving needs at affordable prices. Connecting energy supplies and end-uses requires robust infrastructure that can withstand potential disruptions from physical, geopolitical, and digital threats. Accordingly, energy self-sufficiency can be one important element of energy security.[29]

Security of the energy system is important because Canadians rely on energy for nearly all aspects of daily life. In the case of home heating or electricity, extended disruptions can have serious consequences for the health and wellbeing of individuals. Having secure access to energy also supports the competitiveness of the Canadian economy—businesses and industries depend on reliable access to affordable energy.

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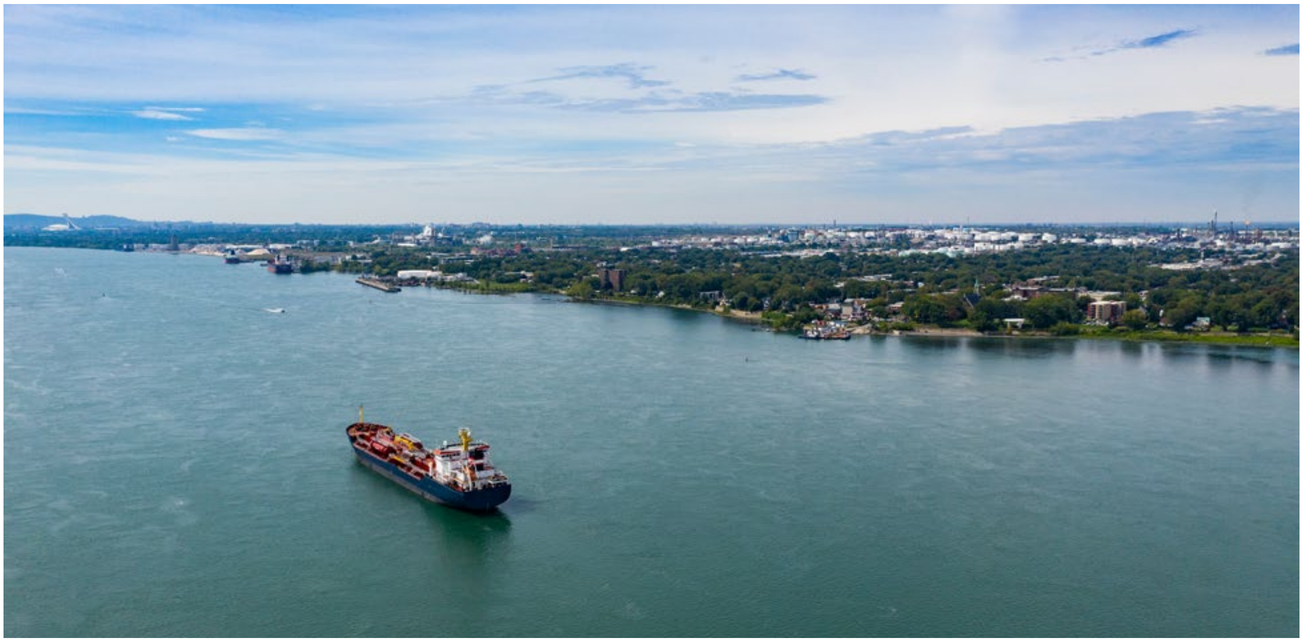
[29] Based on information from the International Energy Agency, Organization for Security and Co-operation in Europe, U.S. Department of Energy, and World Energy Council.

Diversifying the markets for Canada's energy exports has also become a growing focus of the Canadian energy dialogue. Energy trade in Canada is strongly integrated with the U.S. and increasing Canada's access to diverse markets has the potential to enhance Canada's economic resiliency and competitiveness.

In Canada, drivers of energy security and trade diversification can depend on the region or type of energy. Through the lens of this report's projections, we look at three aspects of the Canadian energy system, recognizing that these aspects are not exhaustive and that other energy security considerations fall outside the scope of this analysis:

1. **Energy self-sufficiency—refined petroleum product (RPP) and natural gas markets in Central Canada:** Canada's two most populous provinces, Ontario and Quebec, form a large market for energy. The region currently receives crude oil and natural gas via pipelines from western Canada, much of which travels through the U.S. before crossing the border back to Canada, making it potentially subject to U.S. trade action. Ontario and Quebec also depend on foreign-produced oil and natural gas, particularly from the U.S. This section looks at what the projections could imply for future energy self-sufficiency in the region.
2. **Supply chain resiliency—expanding Canada's electricity system:** The projections in all scenarios suggest that Canada's electricity system is set to grow faster, in some cases much faster, than in recent history. This section looks at the investment levels, physical assets, and material requirements implied by the scenarios, and the potential implications for supply chain resiliency critical to growing Canada's electricity supply.
3. **Export diversification—western Canadian crude oil production:** In 2024, crude oil made up nearly 20% of the value of all of goods exported from Canada, and over 95% of Canada's crude oil exports were shipped to the U.S. This section compares existing western Canadian oil export infrastructure with the crude oil production projections to understand the potential implications for future crude oil trade diversification.



Energy Self Sufficiency—Refined Petroleum Products and Natural Gas Markets in Central Canada

Compared to many countries where a significant portion of energy is imported, Canada, overall, is relatively energy self-sufficient. At the same time, the types of energy used in different regions across Canada do not always align with locally available resources.

A key example is the Ontario and Quebec market for natural gas and RPPs (e.g., gasoline and diesel). While central Canada is a large consumer of both, the region produces little to no natural gas or crude oil—crude oil being the primary input for producing RPPs at refineries. Significant energy transportation infrastructure exists to supply the region with these fuels from other provinces and from abroad, primarily the U.S.

Recent trade and geopolitical developments have heightened interest the steps Canadian policy makers and businesses could take to enhance energy self-sufficiency. In central Canada, this could include increasing the share of domestically produced crude oil and natural gas that is supplied to the region, as well as reducing reliance on pipelines that currently transit through the U.S. It could also include shifting the region's fuel mix to energy sources that can be produced within the region, such as electricity.

Key Takeaways

In the Current Measures, Higher, and Lower scenarios, use of RPPs (and hence crude oil) and natural gas in central Canada is stable over the projection period. The major pipeline systems delivering crude oil and natural gas to the region are likely currently operating near their capability to deliver volumes into central Canada, implying that the region's energy security would not significantly change absent major energy transportation infrastructure changes.

In Canada Net-zero, lower RPP and natural gas use over the projection period could enhance energy self-sufficiency by increasing the share of energy that could be produced locally, such as electricity and hydrogen.

Refined Petroleum Products

Combined, Ontario and Quebec consumed just over 900 Mb/d of RPPs in 2024, nearly half of all the RPPs used in Canada that year. RPPs are primarily used in the transportation sector to move people and goods, with the petrochemical sector also making up a sizable portion of demand in Ontario.

Most RPPs in the region are produced at 6 domestic refineries (4 in Ontario and 2 in Quebec), which together can process almost 800 Mb/d of crude oil. In 2024, Central Canada imported 127 Mb/d of RPPs and exported 124 Mb/d. RPPs are both imported and exported due to factors such as refinery configurations, local logistics, and seasonal supply and demand fluctuations.

RPPs are transported within the region by rail, marine, and truck shipments, as well as by the Trans-Northern Pipeline, which distributes RPPs from refineries in Montreal and southern Ontario to delivery points in both provinces.

Refined Petroleum Product Use

The projections for RPP use in Ontario and Quebec largely match the broader RPP trends for Canada. As shown in Figure S.1, in the Current Measures, Higher, and Lower scenarios, total RPP use in Ontario and Quebec is relatively flat over the projection period, staying below pre-2020 levels through 2050.

While total RPP demand is relatively stable in these three scenarios, the share of different types of fuels changes significantly. The share of passenger EVs grows briskly[30], putting considerable downward pressure on gasoline use as it is replaced by electricity as the main fuel for passenger transportation. As shown in Figure S.2, partially offsetting declining gasoline use is growing demand for diesel (for freight transportation), which occurs in the Current Measures, Higher, and Lower scenarios.

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[30] Note that our modeling includes policies in place as of November 2025, which includes the Electric Vehicle Availability Standard with a target of 100% ZEV sales by 2035. In early February 2026, the Government of Canada announced it would repeal the Electric Vehicle Availability Standard in favour of other measures with an aspirational goal of 90% ZEV sales by 2040. These changes could reduce the pace of EV adoption compared to what we have modeled.

Figure S.1: Ontario and Quebec combined RPP demand, all scenarios

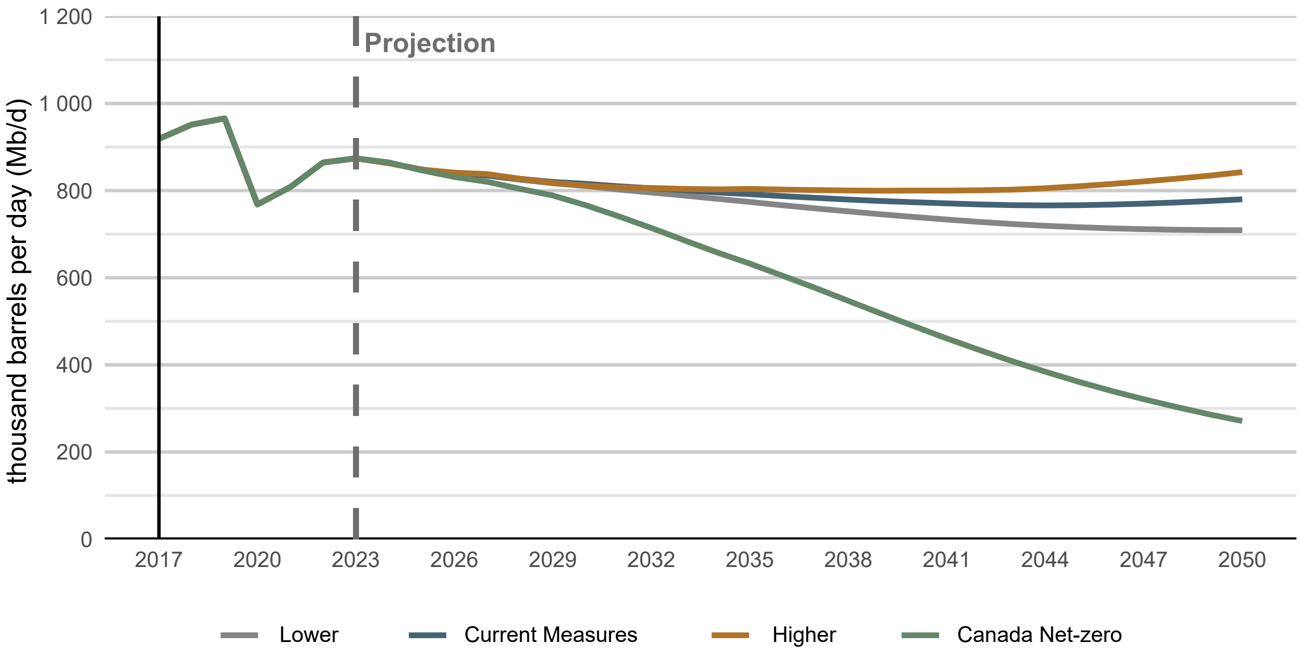
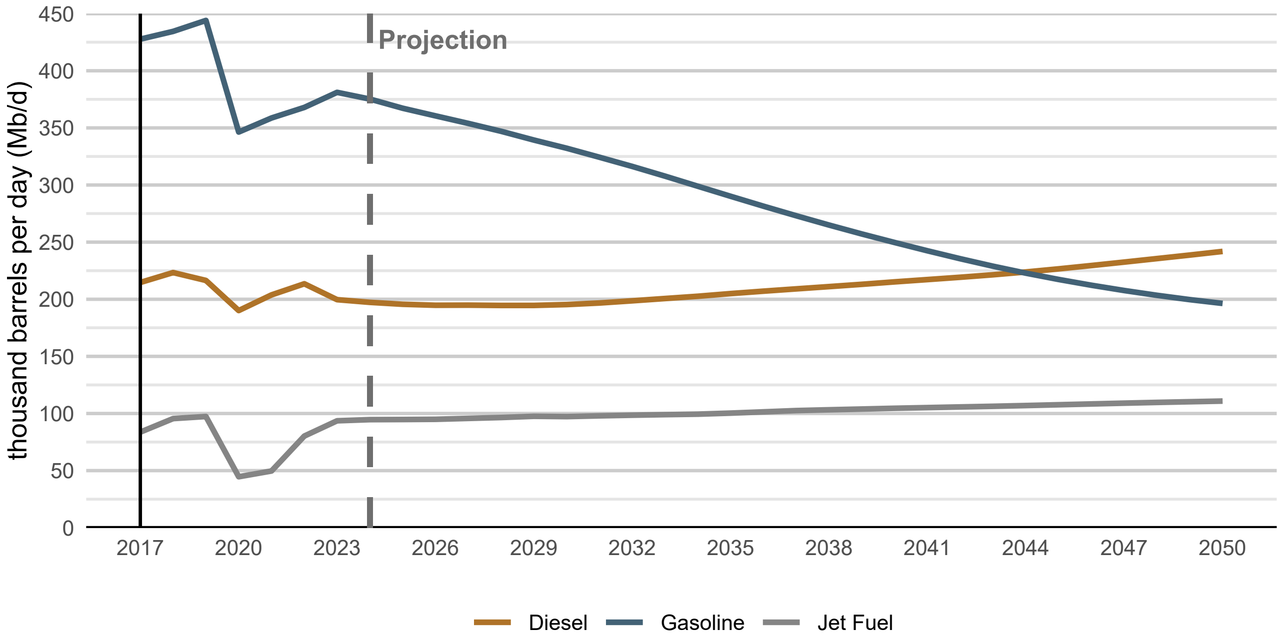


Figure S.2: Ontario and Quebec gasoline, diesel and jet fuel demand, Current Measures



This shift in fuel use has the potential to somewhat enhance central Canada's energy self-sufficiency. The region has been a net importer of gasoline and a net exporter of diesel for many years. In 2024, the region imported 62 Mb/d of gasoline and only 2 Mb/d of diesel, while exporting 50 Mb/d of diesel and 22 Mb/d of gasoline. Lower gasoline demand could mean fewer RPP imports while growing use of diesel could be met through reduced exports of that fuel.

Jet fuel use increases by 18% from 2023 to 2050 in Current Measures and increases steadily in the Higher and Lower scenarios, reflecting continued increases in passenger air transportation. In 2024 nearly a third of jet fuel used in the region was imported. Significantly increasing domestic jet fuel production would likely require significant changes to existing refining infrastructure in the region.

Total RPP use in central Canada in Canada Net-zero drops significantly compared to the other scenarios, as shown in Figure S.1. Beyond the high adoption of passenger EVs in the other scenarios, Canada Net-zero sees greater growth in electrification of light freight vehicles and use of hydrogen in heavy-duty freight vehicles, as well as increasing use of sustainable aviation fuel instead of jet fuel. This drop in demand means there is potential to reduce the amount of RPPs imported into the region. It also reduces crude oil requirements in the region, including imports of crude oil from the U.S. In Canada Net-zero, more electricity and hydrogen are produced locally, which could enhance the region's energy self-sufficiency. Increasing production of electricity and using more electricity to produce hydrogen may, however, face other challenges, as described in the following section in this chapter: Supply Chain Resiliency—Expanding Canada's Electricity System.

Crude Oil

Crude oil is the main input to produce RPPs at refineries. The volumes of RPPs and crude oil discussed in this section can be compared in broad terms, but are not strictly comparable, given factors such as the volumetric changes during the refining process.

Western Canadian crude oil is a key feedstock for Ontario and Quebec refineries. This supply reaches the region via the Enbridge Mainline pipeline system which traverses the prairies and U.S. Midwest before reaching southwest Ontario at Sarnia. In 2024, total flows on the pipeline system into Sarnia averaged 733 Mb/d. Most of these flows are crude oil produced in western Canada, but they also include some U.S. crude oil production—104 Mb/d in 2024. Another option for central Canada to access crude oil is via marine vessel shipments at Quebec City and other ports along the St Lawrence Seaway. Total imports of foreign crude oil to the region (via both the Enbridge Mainline and marine vessel) have been stable over the past several years at around 200 Mb/d. Since 2019, virtually all these imports of foreign crude oil into central Canada have come from the U.S.

Supply of Canadian Crude Oil

Total future Canadian crude oil production is relatively robust in all scenarios, as described in the Results chapter. In all scenarios, crude oil production remains well above crude oil feedstock requirements at Canadian refineries implied by the RPP demand projections.

Crude oil type is also important as refineries in Ontario and Quebec are mostly optimized to use light crude oil (which can include bitumen that is upgraded into synthetic crude oil). Some refineries in the region can use some heavier crude oil feedstocks, with 159 Mb/d of heavy crude oil flowing into central Canada on the Enbridge Mainline system in 2024. In all scenarios, heavy crude oil makes up a growing share of production. However, light crude oil remains a significant portion of total western Canadian production, suggesting that the type of crude oil produced in Canada is unlikely to be a constraint in increasing self-sufficiency.

Access to Crude Oil

This section focuses on the energy self-sufficiency trends for the region in the Current Measures, Higher, and Lower scenarios where crude oil use is relatively stable over the projection period.

There are two main options for the region to obtain crude oil: marine vessel via ports along the St. Lawrence Seaway and the Enbridge Mainline pipeline system. Some smaller volumes of crude oil may also reach the region by rail.

Currently, approximately half[31] of central Canada's 200 Mb/d of crude oil imports arrive by marine vessel, with essentially all those volumes coming from the U.S. The other half was the portion of crude oil produced in the U.S. that flowed on the Enbridge Mainline pipeline system.

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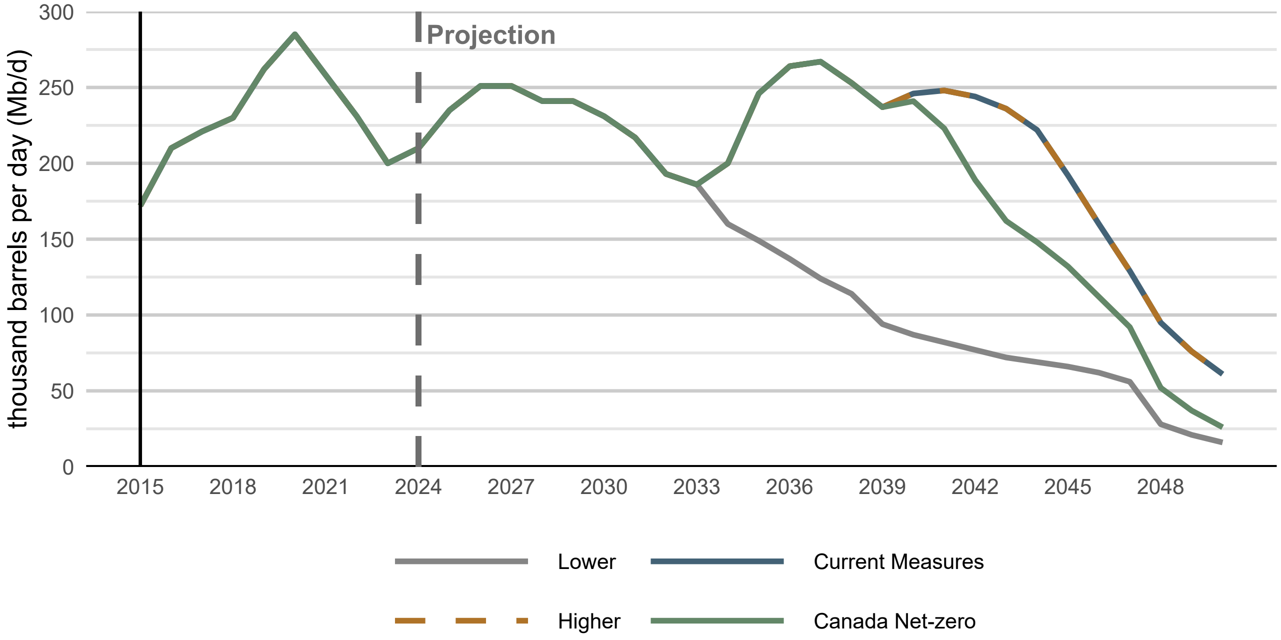
[31] There is limited data on the mode of transportation used to import crude oil. Imports by marine vessel are estimated based on total crude oil import volumes in 2024 less volumes of crude oil produced in the U.S. flowing on the Enbridge Mainline.

It may be possible to reduce reliance on foreign crude oil imports and enhance self-sufficiency in the region by replacing some volumes imported by marine vessel with crude oil produced in Newfoundland and Labrador. Currently, most of Newfoundland and Labrador's crude oil production, which was 210 Mb/d in 2024, is exported internationally, with nearly 60% destined to the U.S. and the remainder mostly going to Europe.

As shown in Figure S.3, in Current Measures, crude oil production in Newfoundland and Labrador could partially offset import volumes to central Canada until around 2045 when production begins a natural decline. This drop occurs sooner in the Lower scenario. Offsetting imported crude oil with Newfoundland and Labrador production may require changes to the refining infrastructure in central Canada as the specifications of Newfoundland and Labrador production are somewhat different compared with the types of crude oil the refineries on Ontario and Quebec are optimized for.

Given the sustained level of RPP demand in the Current Measures, Higher, and Lower scenarios, there may also be potential to increase the amount of crude oil the region can source via marine vessel. Prior to 2014, most of the crude oil imported into Ontario and Quebec was from countries other than the U.S., with Algeria, United Kingdom and Norway being major sources.

Figure S.3: Newfoundland and Labrador crude oil production, all scenarios



Total imports were also higher than current levels, averaging 494 Mb/d from 2000 to 2013, and as high as 590 Mb/d in 2005. During this period, the Enbridge Line 9 pipeline flowed east to west, meaning crude oil brought in via marine vessel could reach refineries all the way to southern Ontario. In two phases between 2013 and 2015, Enbridge Line 9 was reversed to flow west to east. While increasing imports of crude oil by marine vessel would not enhance the energy self-sufficiency of the region, it could allow greater diversification of import origins, which currently are entirely from the U.S. Significantly increasing volumes brought in via the St. Lawrence Seaway from current levels (either imports or volumes from Newfoundland and Labrador) would require infrastructure changes, including potentially reversing again, the flow of crude oil to move east to west on Enbridge's Line 9.

The Enbridge Mainline system is the region's other main source of crude oil. Beginning in Edmonton, Alberta, the system enters the U.S. in southern Manitoba. The system then runs through the U.S. making deliveries at refineries and interconnecting pipelines in the Great Lakes and Chicago regions before re-entering Canada at Sarnia in southwest Ontario. From Sarnia, the Enbridge Line 9 pipeline moves crude oil east to refineries in the region.

The Enbridge Mainline system includes a substantial segment that runs through the U.S., which is relevant in assessing the energy self-sufficiency of central Canada. As the main connection between western Canadian production and the region, an extended disruption on the system could create a significant challenge in meeting current and projected RPP demand. There is no crude oil pipeline that runs entirely within Canada that connects western Canadian production with eastern Canadian refineries. Connecting western Canadian crude oil supply to the region via a pipeline running entirely within Canada would require major new infrastructure.

RPP use in central Canada in the Current Measures, Higher, and Lower scenarios is relatively stable, falling gradually from 874 Mb/d in 2023, to 780 Mb/d in Current Measures, 842 Mb/d in the Higher scenario and 709 Mb/d in the Lower scenario by 2050. Average flows on the Enbridge Mainline pipeline system into central Canada averaged 750 Mb/d from 2019 to 2024, with monthly peak volume over that period closer 850 Mb/d. While RPP and crude oil volumes are not directly comparable, this suggests that the capability of the Enbridge Mainline to deliver into central Canada is roughly proportional in overall scale to RPP demand projected in the Current Measures, Higher and Lower scenarios.

Natural Gas

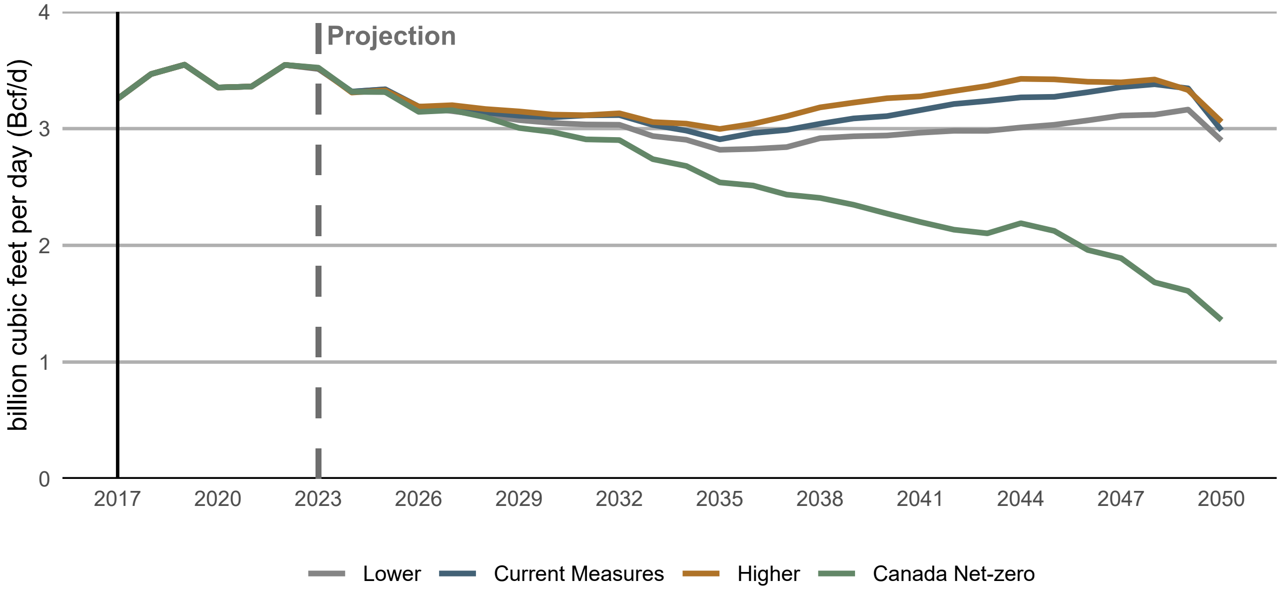
In 2023, central Canada used 3.5 Bcf/d of natural gas, mostly in Ontario. Combined, the region's consumption was roughly a quarter of total Canadian natural gas use. The main uses for natural gas in the region include space heating, power generation, and in industries like chemicals and iron and steel.

Imports of natural gas from the U.S. to central Canada have been stable between 1.6 and 1.7 Bcf/d over the past several years, representing just less than half of the region's total gas use. Ontario and Quebec are part of a highly integrated North American natural gas market. The region receives natural gas from numerous pipelines originating in western Canada and the U.S.

Natural Gas Use

The projections of primary natural gas demand in central Canada follow similar patterns to the projections of Canada. As shown in Figure S.4, in the Current Measures, Higher and Lower scenarios, natural gas use declines gradually over the first decade of the projection period largely due to existing climate policies. Later, natural gas use begins to increase slightly, driven by growth in economic activity and power generation.

Figure S.4: Ontario and Quebec combined primary natural gas demand, all scenarios



In Canada Net-zero, natural gas use in the region falls nearly two thirds from 2023 to 2050, reflecting the steady adoption of heat pumps for home heating and cooling, industrial electrification, and strong energy efficiency improvements. In this scenario, the need to bring natural gas from outside of central Canada is lower. Instead, some of the energy needs currently served by natural gas are met by locally generated electricity, which increases to meet higher demand. Lower reliance on external energy sources could enhance the region's self-sufficiency in Canada Net-zero compared to the other scenarios.

Supply of Canadian Natural Gas

In all scenarios, Canadian natural gas production remains high enough to meet future Canadian consumption. Production, which was at 18 Bcf/d in 2024, grows in all scenarios, reaching as high as 31 Bcf/d in the Higher scenario by 2050 and as low as 21 Bcf/d in Canada Net-zero.

Access to Natural Gas

Central Canada can source natural gas from western Canada and various producing regions in the U.S. The market operates in an integrated fashion, with natural gas moving in and out of Ontario and Quebec at different points via a significant network of natural gas pipelines.

The TC Energy Canadian Mainline (TC Mainline) is the largest pipeline system moving natural gas from western Canada eastward. The TC Mainline traverses the prairies before dividing into two segments in Manitoba: one that carries gas east, north of the Great Lakes, and one that carries gas south to the U.S. Natural gas exiting western Canada on other pipelines, such as Alliance or Foothills, can also make its way to Ontario and Quebec through interconnecting pipelines in the U.S.

The TC Mainline delivers natural gas to central Canada without traversing the U.S. This segment is referred to as the Northern Ontario line (NOL) segment and had a reported average annual capacity of 3.4 Bcf/d from 2019 to 2024, with throughput averaging 1.5 Bcf/d over the same period. Average throughput on the segment was closer to 2 Bcf/d in 2024, representing about 60% of the region's total demand.

As shown in Figure S.4, in the Current Measures, Higher and Lower scenarios, natural gas use in the region remains near current levels throughout the projection period. In those scenarios, central Canada's energy self-sufficiency could be enhanced by increasing the amount of natural gas produced in Canada used in the region, particularly if it is delivered via a route entirely within Canada. Increasing natural gas volumes on the NOL segment offers potential to do so but would depend on whether there is capability to increase volumes on the segment in the future.

In the past, volumes on the NOL segment have been higher, up to 3.2 Bcf/d in 2006. However, since 2006 there have been changes to the system, including the conversion of one of the lines of the prairies segment of the pipeline from natural gas to oil service as part of the Keystone oil pipeline in 2008. While recently reported NOL capacity was well above throughput, significantly increasing NOL throughput may not be feasible due to system constraints upstream or downstream of the segment. For example, the NGTL system, which gathers natural gas in Alberta and northeast B.C., is largely at full capacity at the point where it delivers natural gas to the TC Mainline at the Alberta/Saskatchewan boundary. It is likely that significantly increasing the amount of NOL-delivered western Canadian natural gas used in central Canada would require infrastructure investments, potentially both upstream and downstream of the NOL segment.

Summary

Diverse transportation infrastructure systems are important to the security of central Canada's RPPs, crude oil, and natural gas supply. Western Canada and the U.S. are the main sources of the region's crude oil and natural gas.

For both crude oil and natural gas, central Canada's access to western Canadian production relies on major pipeline systems moving volumes from west to east. Currently, a significant share of the region's needs is met by western Canadian crude oil and natural gas, though much of that supply arrives via pipelines that transit through the U.S. In addition, imports of those commodities from the U.S. play a significant role. In the Current Measures, Higher and Lower scenarios, total demand for RPPs and natural gas is relatively stable near current levels throughout the projection period. Both major pipeline systems delivering crude oil and natural gas to the region are likely currently operating near their full capability to deliver volumes into eastern Canada, implying that the region's energy security would not significantly change absent major infrastructure changes.

In Canada Net-zero, demand for RPPs (and hence crude oil) and natural gas, decline sharply over the projection period. This could enable the region to reduce the need to rely on foreign energy sources and Canadian energy delivered through the U.S. In this scenario, shifting the energy mix to a higher share of energy produced within the region, like electricity and hydrogen, could enhance energy self-sufficiency in Ontario and Quebec.

Supply Chain Resiliency—Expanding Canada's Electricity System

As described in the Electricity section of the Results chapter, all scenarios project electricity generation growing more quickly in the future compared to the past 20 years. In Current Measures, electricity generation grows by nearly 50% from 2024 to 2050, and more than doubles in Canada Net-zero.

Expanding Canada's electricity system to meet growing demand will require significant levels of investment. It will also rely on a complex supply chain to produce the components and materials required to facilitate this expansion.

The following section contextualizes the electricity supply projections by exploring the capital and repair expenditure requirements associated with the scenarios and quantifying the electricity component demands, such as solar panels or gas turbines, implied by the projections. The analysis also looks at the material requirements, such as copper, silicon and other critical minerals, used to build those components.

Key Takeaways

Growing Canada's electricity supply as depicted in all scenarios will require considerable investment, with cumulative capital and repair expenditures from 2025 to 2050, ranging from as high as \$2025 1.2 trillion in the Higher and Canada Net-zero scenarios and \$2025 785 billion in the Lower scenario.

These investments will depend on a complex global supply chain to produce physical components such as solar panels or natural gas turbines. The manufacturing of those components, and the extraction and processing of materials required to manufacture them, is often highly concentrated in individual countries, which is a risk to the resiliency of the supply chain.

Future growth in Canada's demand for electricity system components is relatively modest compared to the total size of the global capacity to produce those components. However, if the trend of growing electricity use around the world continues and possibly accelerates, there is potential for supply chain challenges to impact the cost and availability of different technologies. Canada plays a role in producing several of the minerals that are important inputs to the global electricity component supply chain, so increasing Canadian and/or global investments could present opportunities as well.

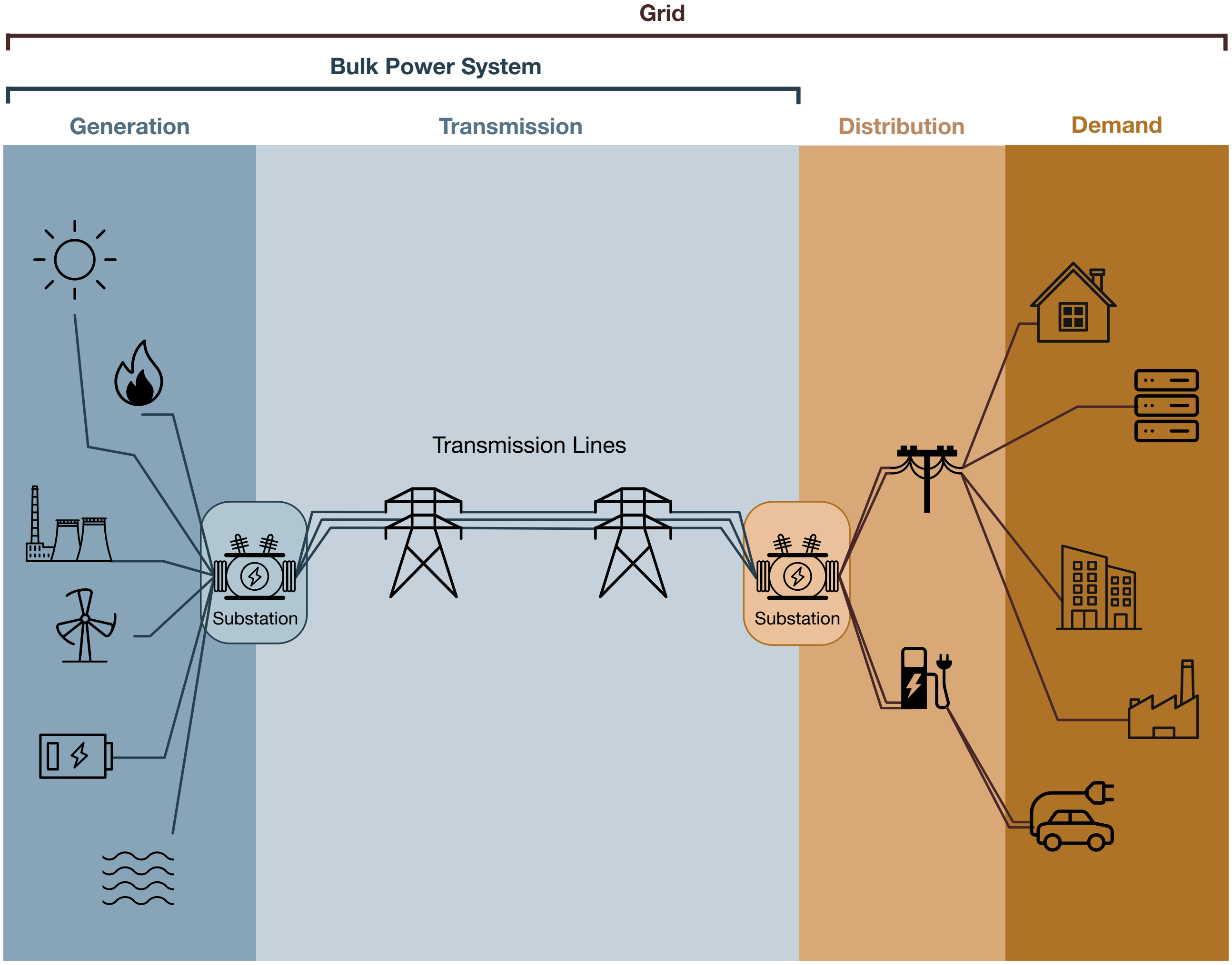
Investment in the Electricity System

Electricity grids are interconnected systems of physical components working in tandem to ensure reliable delivery of electricity. These components can include generating facilities, transmission lines, transformers, control and communication systems, and distribution infrastructure. Figure S.5 depicts the key elements of an electricity grid.

How investments in new electricity generation and transmission are made varies by province and territory. Expenditures on maintaining or growing each electricity system are, in general, ultimately paid for by those that use the electricity through the rates they pay.

Capital and repair expenditures in Canada's electricity sector, including expenditures on new assets like generating facilities, transmission lines and distribution systems, as well as specific repair and maintenance activities, averaged $2025 32 billion from 2006 to 2023, growing at an annual average rate of 3.7% over that period.

Figure S.5: Main elements of a typical power grid

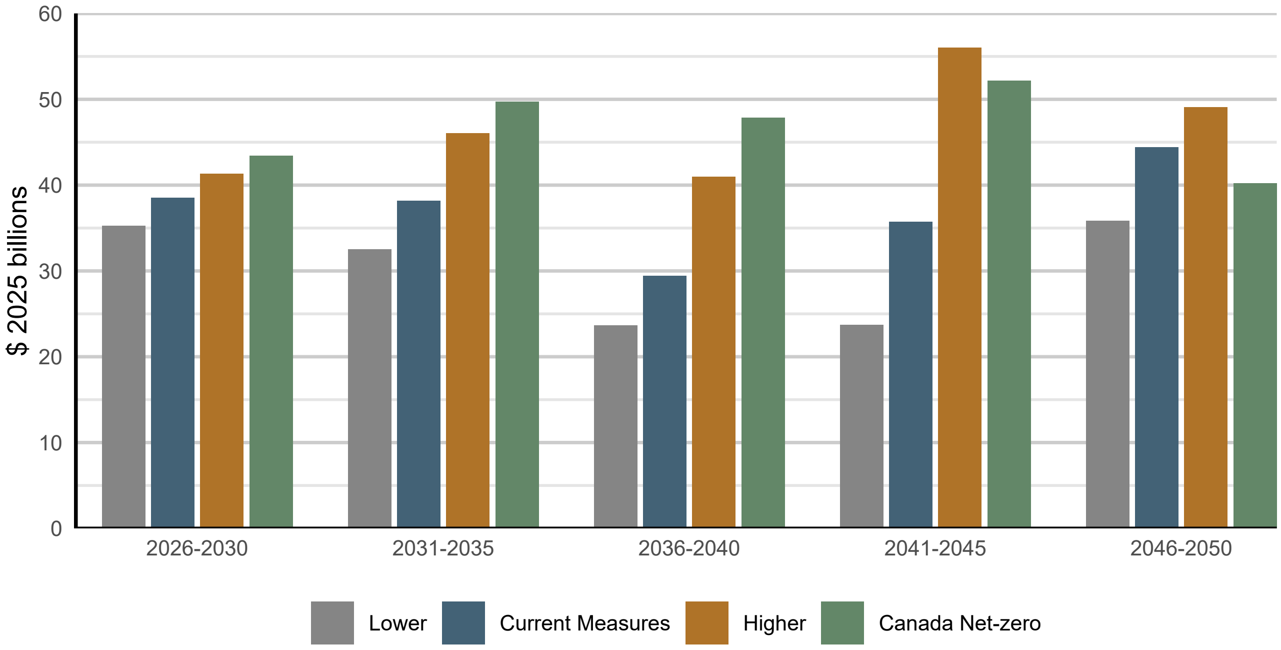


Our estimates of capital and repair expenditures over the projection period are not directly comparable to the available data from Statistics Canada, with estimates representing a subset of the available historical data. Our estimates exclude expenditures on the distribution system and transmission lines other than those built to connect new generation to the system or between provinces. This is because our electricity model focuses on the bulk power system and excludes a detailed representation of the distribution system and certain transmission types.

Even though our projections of capital and repair expenditures exclude a portion of the expenditures reported in the historical data, the estimates of capital and repair expenditures in all but the Lower scenario are higher than the historical data from the past two decades despite their inclusion of all investment in the electricity sector. Average annual capital and repair expenditures in Current Measures is $2025 37 billion from 2025 to 2050 ($2025 962 billion cumulatively) and $2025 46 billion in the Higher and Canada Net-zero scenarios ($2025 1.2 trillion). In the Lower scenario, capital and repair expenditures average $2025 30 billion per year, or $2025 785 billion cumulatively. Our assumptions regarding capital costs influence the capital expenditure estimates: while total installed capacity increases almost two thirds as much from 2025 to 2050 in Canada Net-zero compared to Current Measures, cumulative expenditures over the projection period in Canada Net-zero are only 25% higher.

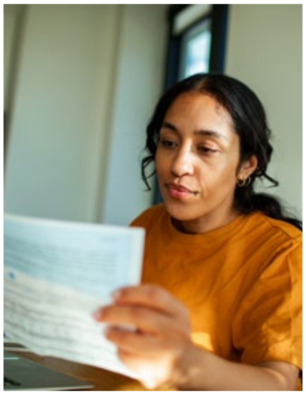
Figure S.6 shows average annual capital and repair expenditures in 5-year increments for each of the four scenarios. Expenditures on the distribution system and certain transmission types are excluded.

Figure S.6: Average annual investment in the electricity system, all scenarios



In all four scenarios, capital and repair expenditures are relatively high in the first decade of the projection periods as utilities and companies add capacity to accommodate demand growth as well as reduce the emission-intensity of their generation fleets. After that, expenditures remain high in the Higher and Canada Net-zero scenarios, reflecting higher electricity use in those scenarios. Expenditures slow in the Current Measures and Lower scenarios from 2036 to 2045 and then increase again near the end of the projection period to accommodate continued demand growth, replacement of retiring assets, and further emission reductions.

The price consumers pay for electricity in the modeling is based on the projections of total electricity system costs, which includes capital and repair expenditures and operating costs of facilities, as well as assumptions related to the cost of delivering electricity to consumers. These prices in turn influence our other models. In general, electricity prices rise in all four scenarios but at a pace similar to the increase over the past 30 years. Average Canadian electricity prices increase slightly faster than the rate of inflation in the Current Measures, Higher and Lower scenarios, and slightly slower in Canada Net-zero. Prices are lowest in Canada Net-zero despite having the highest electricity demand growth, largely due to lower capital cost assumptions for clean electricity technologies in that scenario.



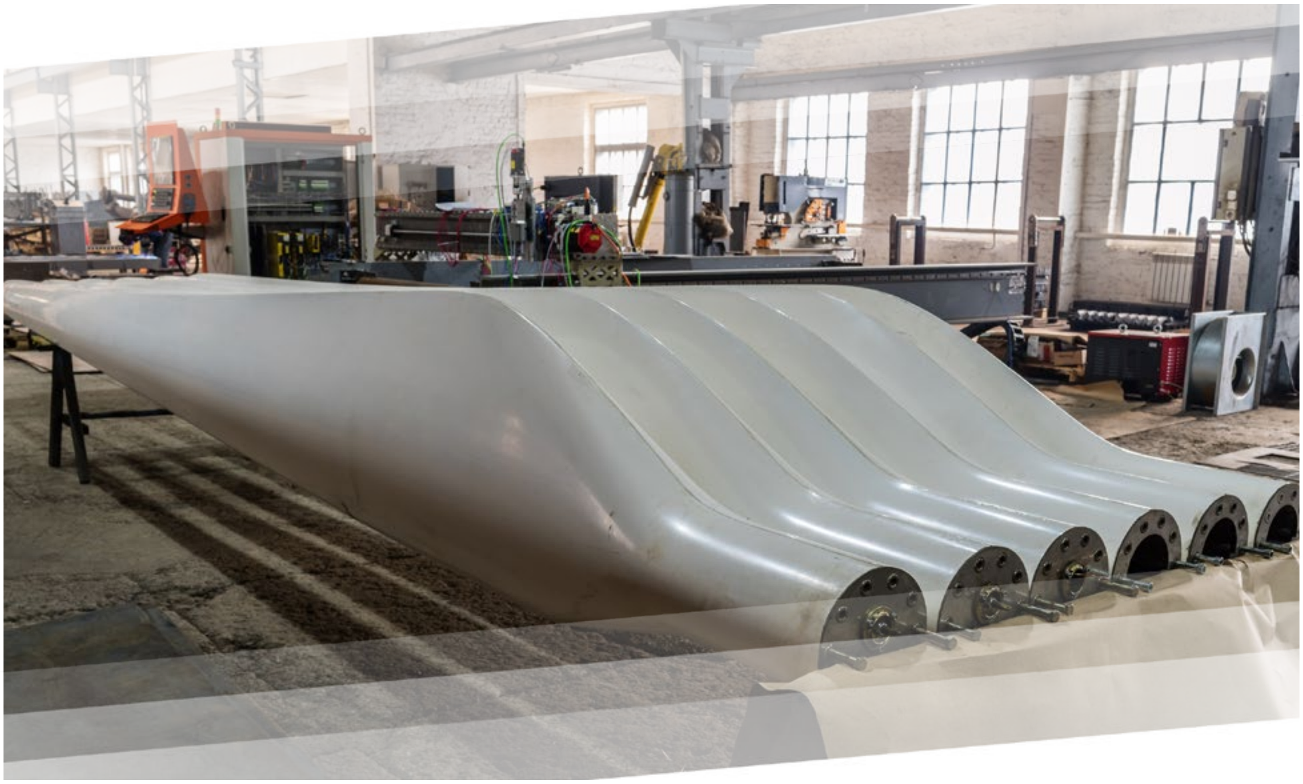
Components and Material Requirements

Given the importance of electricity systems to modern economies, governments around the world are placing greater strategic importance on the components and materials that make up these systems, including the resiliency of the supply chains. The following section quantifies what the projections imply about the need for these inputs in Canada and explores the resiliency of the supply chain required to support those projections.

Global Electricity Component Supply Chain

The supply of the physical components that make up electricity grids depends on a complex and interconnected supply chain. The manufacturing and resource extraction and processing activity to produce these components is global in nature. However, in many cases, these activities are often concentrated in specific countries. For example, according to the International Energy Agency (IEA), China accounts for more than 80% of solar module manufacturing capacity and 70-80% of wind turbine blades. Likewise, production of some key raw materials like chromium (South Africa, 45%), silicon (China, 85%) and cobalt (Congo, 76%) are highly concentrated in individual countries according to the U.S. Geological Survey. Market concentration in the refining and processing of raw materials is also high, with China dominating many minerals, including 70-75% of global lithium and cobalt processing and over 90% for rare earth elements and battery-grade graphite, according to the IEA.

A high degree of concentration of these activities in one or a few countries can make a supply chain less resilient. Changes to trade practices, geopolitical events or natural disasters in one region can result in greater shortages or more rapid price increases compared to a more diversified supply chain.



Projections – Implied Component and Material Requirements

Accelerating the growth of Canada’s electricity supply requires more physical assets to be installed. Table S.1 shows the cumulative number of components installed in Canada from 2025 to 2050 implied by the capacity expansions projected in Current Measures and Canada Net-zero.

Table S.1 – Estimated key electricity system components installed, Current Measures and Canada Net-zero

Component	**Estimated cumulative quantity installed, 2025 to 2050**	
	Current Measures	**Canada Net-zero**
Solar (total surface area of panels)	105 km^2	97 km^2
Onshore wind turbines (reference capacity of 5.5 MW)	10,718	17,511
Offshore wind turbines (reference capacity of 15 MW)	73	89
Lithium batteries (reference battery stack size of 4.5 MWh)	5,324	6,620
Gas turbines (reference capacity of 100 MW)	124	131
Gas turbines with CCUS (reference capacity of 100 MW)	74	89

On its own, faster growth of Canadian electricity systems will likely have limited impact on the global electricity component supply chain as Canada is a relatively small purchaser compared to the global market. However, accelerated electrification globally could compound pressure on the global supply chain, and in turn could affect the timeliness and cost of acquiring new electricity system components in Canada.

Domestically, accelerating growth in electricity system installations could create other challenges. For example, it could be challenging to access enough skilled labour involved to construct these facilities. A report by the Electricity Human Resources Canada projected that job openings in the electricity sector could be between 17,000 and 28,000 from 2023 to 2028 (compared to total employment of 110,600 in 2022) driven by new positions and retirements of existing employees. While this represents an opportunity for job creation, acute labour shortages could affect the timelines and costs of bringing new generation online.

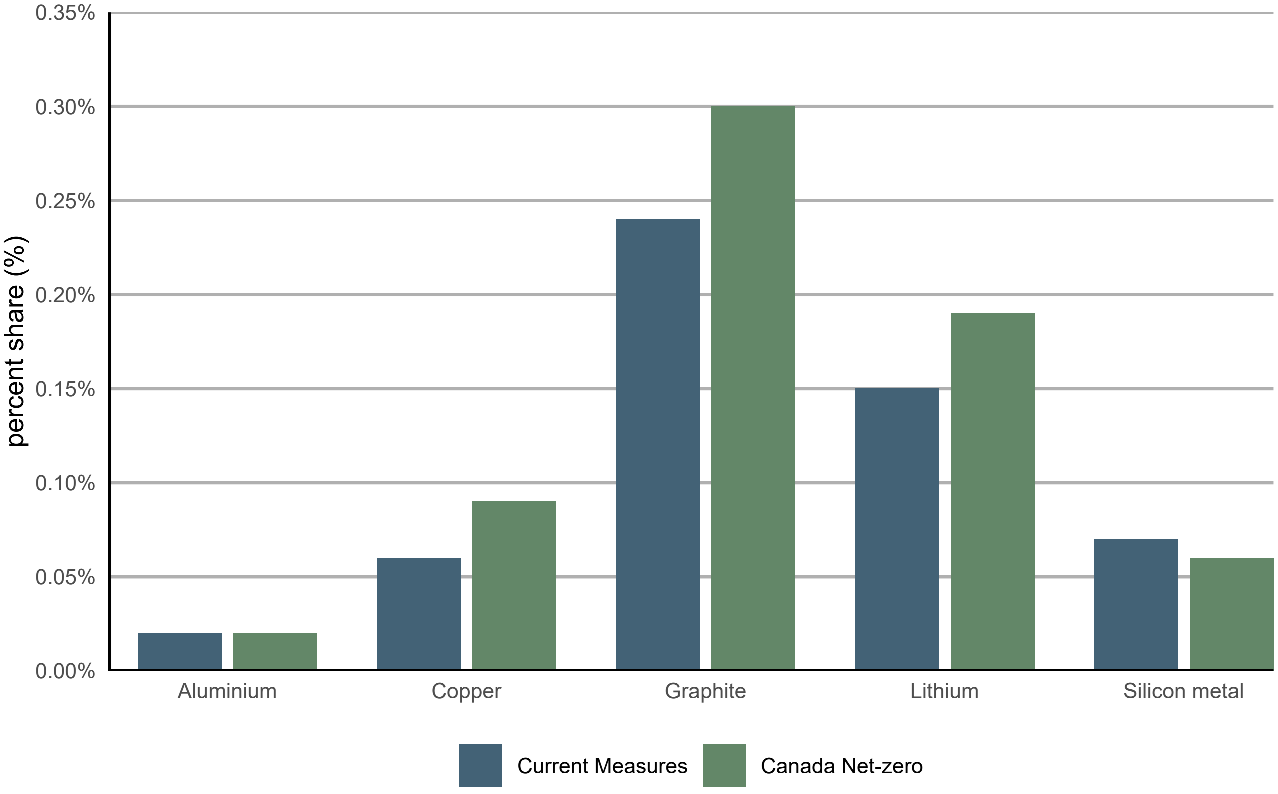
Manufacturing electricity system components requires a wide variety of materials. For example, manufacturing a solar panel requires materials like aluminum, silicon and copper. Table S.2 quantifies the demand for a subset of key materials required by the new installations of electricity components implied by the projections. Several materials listed in Table S.2 are on the Government of Canada's critical mineral list.

Table S.2 – Selection of estimated material demand implied by cumulative electricity capacity expansions, Current Measures and Canada Net-Zero

Material	Estimated cumulative tonnes used, 2025 to 2050	
	Current Measures	Canada Net-zero
Aluminum	398,165	443,853
Concrete	24,746,609	39,848,627
Copper	365,398	564,733
Dysprosium	638	1,034
Glass and carbon fibre composites	453,090	735,740
Graphite	101,429	126,420
Lithium	9,269	11,580
Neodymium	7,838	12,725
Praseodymium	1,188	1,925
Silicon metal	78,053	72,733
Solar glass	1,003,945	935,230
Steel	8,099,356	12,109,150

To contextualize the material use associated with projections, Figure S.7 shows the average annual requirements of some of the materials in Table S.2 compared to global production of those materials in 2024. This comparison provides a sense of how large the implied demand for materials compares to current availability.

Figure S.7: Average annual implied material demand from 2025 to 2050 in Canada as a percentage of 2024 global production of key minerals, Current Measures and Canada Net-zero

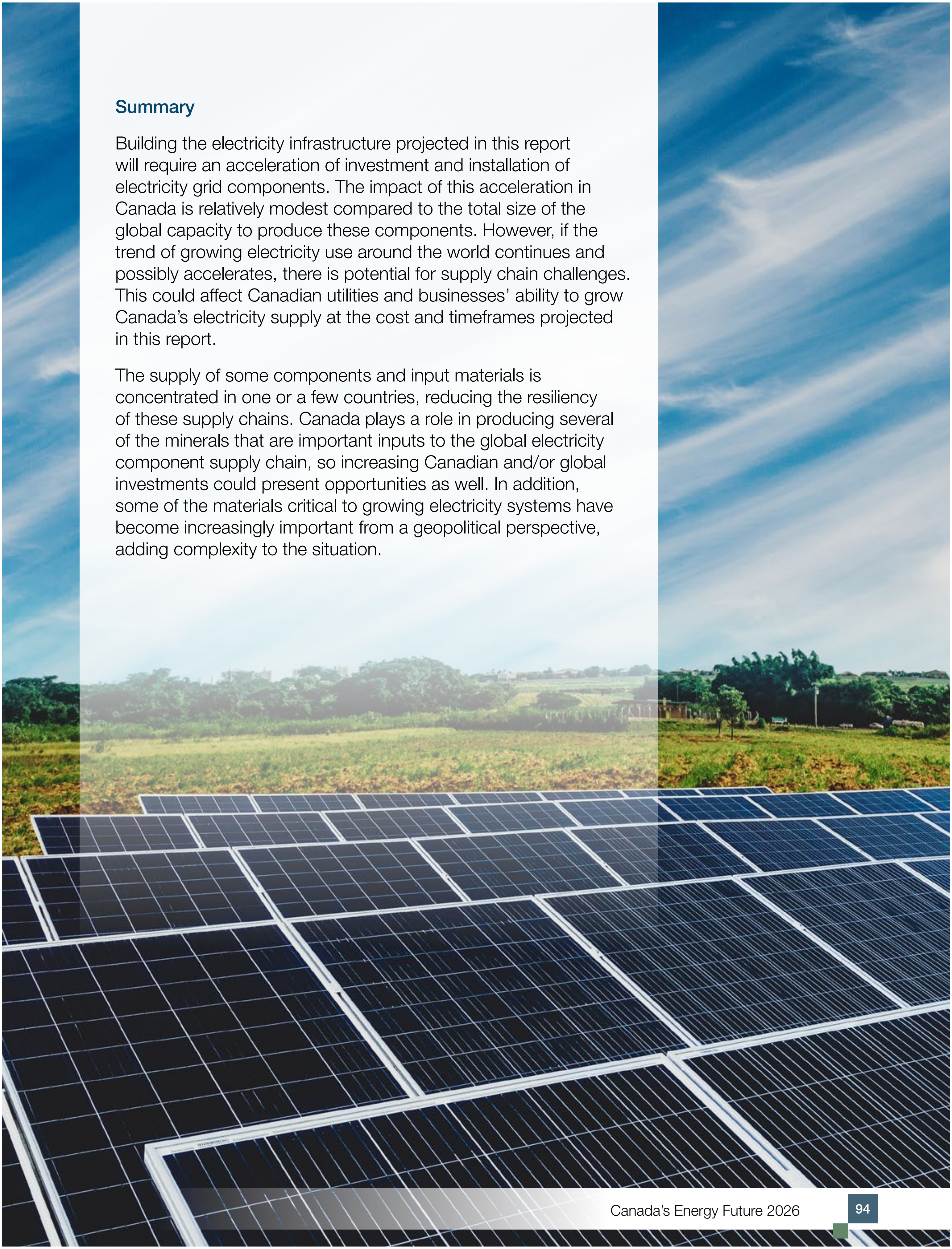


Canada plays a role in producing several of the minerals that are important inputs to the global electricity component supply chain, including nearly 5% of global aluminum smelter production in 2024, as well as notable quantities of copper, cobalt, lithium and graphite. Canada's Critical Mineral Strategy aims to increase the supply of Canadian critical minerals with a focus on objectives like economic growth, competitiveness, climate action and advancing Reconciliation with Indigenous peoples. Given that production of many critical minerals is concentrated in a handful of countries, increasing diversity of producing regions, including Canada, could enhance the resiliency of the global electricity component supply chain and Canada's access to those components.

Summary

Building the electricity infrastructure projected in this report will require an acceleration of investment and installation of electricity grid components. The impact of this acceleration in Canada is relatively modest compared to the total size of the global capacity to produce these components. However, if the trend of growing electricity use around the world continues and possibly accelerates, there is potential for supply chain challenges. This could affect Canadian utilities and businesses' ability to grow Canada's electricity supply at the cost and timeframes projected in this report.

The supply of some components and input materials is concentrated in one or a few countries, reducing the resiliency of these supply chains. Canada plays a role in producing several of the minerals that are important inputs to the global electricity component supply chain, so increasing Canadian and/or global investments could present opportunities as well. In addition, some of the materials critical to growing electricity systems have become increasingly important from a geopolitical perspective, adding complexity to the situation.



Western Canadian Crude Oil Production—Export Diversification

Canada is a trade-oriented economy, with exports equal to around 30% of its economic output. Over three quarters of the value of Canada's exports went to the U.S. in 2024, including 94% of motor vehicles and parts, 82% of forest products, and 57% of metal and mineral products. Exports of Canada's crude oil have been even more concentrated, with over 95% going to the U.S. in 2024. The proximity of the U.S. and the size of its economy have been drivers of why so many of Canada's exports are sent south of the border. Strong diplomatic ties, including agreements to reduce trade barriers, have also driven this trend.

In general, diversity in trading partners is beneficial to exporters. This is because disruptions in one market, such as logistical bottlenecks or changes to trade policy, are less impactful to exporters if they have alternative markets.

Recently, changing trade and geopolitical drivers have increased interest in diversifying export markets. This section explores what the crude oil projections in the report may mean for the potential for future crude oil trade diversification.

Key Takeaways

With the production projections in this report, there is somewhat limited potential to diversify Canada's crude oil exports given the extent of existing infrastructure that is oriented towards the U.S. An illustrative comparison of crude oil export capacity—existing, or part of a planned expansion, with a final corporate investment decision—to crude oil available for export from western Canada shows a range of potential outcomes across scenarios, with some showing crude available for export exceeding available export capacity and others remaining below it. In light of the markets served by that capacity, more significant diversification of Canada's crude oil trade could result if supply ends up being higher than what is projected in our scenarios, or if new pipeline capacity to global markets diverts volumes away from U.S. markets.

Crude Oil Export Infrastructure

Canada is the 4th largest crude oil producer in the world, behind the U.S., Saudi Arabia and Russia. Canadian crude oil production hit a record high of 5.1 MMb/d in 2024. The vast majority of Canadian crude oil is produced in Alberta, followed by Saskatchewan, offshore Newfoundland and Labrador, and B.C.

Canada's crude oil export infrastructure has developed with the U.S. as its primary customer, with only one of Canada's major export pipelines, the Trans Mountain System, providing direct access to global markets via marine vessel. After transiting the U.S. on the Keystone, Enbridge Mainline or Express pipeline systems, some Canadian crude oil has, at times, also been re-exported to global markets via ports on the U.S. Gulf Coast. In addition, essentially all of Newfoundland and Labrador's offshore production is exported by marine vessel, allowing access to a range of international markets.

Table S.3 shows the pipelines exiting western Canada, their capacities, the key markets they serve, and the key assumptions for Figure S.8 found later in this section. More information on these pipelines is available on the CER's Pipeline Profiles.

Table S.3: Western Canadian crude oil export pipelines, including assumptions for Figure S.8

Pipeline	Estimated existing takeaway capacity (Mb/d) [32, 33, 34]	Downstream markets
Enbridge Canadian Mainline System	3,227 Mb/d **Assumptions for the purposes of Figure S.8:** Capacity was reduced from the above amount by 80 Mb/d to account for the estimated flow of NGLs on the system. Capacity was also reduced by 33 Mb/d to account for the estimated amount of crude oil produced in North Dakota that enters the system within Canada (both reduce the space available to ship western Canadian crude oil). Capacity was increased by 150 Mb/d in 2027 to reflect Enbridge's planned Mainline Optimization Phase 1 expansion (final investment decision announced on November 14, 2025)	U.S. Midwest and interconnecting pipelines serving other parts of the U.S., particularly the Gulf Coast. A segment of the Enbridge Mainline also re-enters Canada at Sarnia, Ontario. Some crude oil shipped on the system may be re-exported to global markets via marine vessel in the U.S. Gulf Coast.
Trans Mountain System	887 Mb/d **Assumptions for the purposes of Figure S.8:** Capacity was reduced by 44 Mb/d from the amount above to account for the RPPs that flow on the line (reducing space available for crude oil).	B.C. and Washington State, and marine vessel with access to global markets.

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[32] For 2025 and onwards, capacities for Enbridge Canadian Mainline System and Trans Mountain System are based on reported capacity from October 2024 to September 2025 available from the CER's Pipeline Profiles, and adjusted in the future as described in the table. Capacities for Express, Milk River and Aurora/Rangeland are based on capacities also listed on the CER Pipeline Profiles. Capacity assumptions for Keystone are described in the table. Structural rail depicted in the 2025 to 2050 period is based on crude by rail exports from October 2024 to September 2025.

[33] For 2024 and prior, capacities for Enbridge Canadian Mainline System, Trans Mountain System and Keystone are based on reported calendar year capacity from the CER's Pipeline Profiles. Capacities for Express, Milk River and Aurora/Rangeland are based on capacities also listed on the CER's Pipeline Profiles. Historical rail volumes are based on the CER crude by rail export statistics.

[34] Not all takeaway capacity is necessarily available at certain points on a pipeline system due to constraints on other parts of the system.

Pipeline	Estimated existing takeaway capacity (Mb/d) [32, 33, 34]	Downstream markets
Keystone	622 Mb/d **Assumptions for the purposes of Figure S.8:** Although capacity on Keystone in 2025 was affected by a pressure restriction imposed by the U.S. Pipeline and Hazardous Materials Safety Administration, the system's nominal capacity of 622 Mb/d was used for 2025 and onwards.	U.S. Midwest and Gulf Coast. Some crude oil shipped on the system may be re-exported to global markets via ports on the U.S. Gulf Coast.
Express	310 Mb/d **Assumptions for the purposes of Figure S.8:** Capacity was increased from the above amount by 30 Mb/d in 2027 to reflect a planned expansion (final investment decision announced on November 7, 2025)	U.S. Rockies region and other downstream U.S. locations. Some crude oil shipped on the system may be re-exported to global markets via ports on the U.S. Gulf Coast.
Milk River	98 Mb/d	U.S. Rockies region.
Aurora/ Rangeland	45 Mb/d	U.S. Rockies region.
Rail	Structural Rail: 77 Mb/d Actual rail exports, which at times have included variable rail volumes in addition to structural rail, are shown in the historical period in Figure S.8. Structural rail capacity of 77 Mb/d was used from 2025 to 2050.	Rail can provide access to a variety of U.S. markets, including some areas not served by pipeline systems. Structural rail represents crude-by-rail volumes that persist due to lack of pipeline connectivity for producers in Canada or refineries in the U.S. Crude oil exports by rail can be much higher than the structural rail amount, and have reached as high as 412 Mb/d in the past, in response to periods of aggregate pipeline capacity shortfalls (i.e. variable rail).

Some of Canada's crude oil exports are moved by rail, though it is generally more expensive than transportation by pipeline. In 2024, crude oil exports by rail averaged 89 Mb/d. Exports by rail can be sent to most regions in the U.S.

A key challenge facing western Canadian crude oil exporters over the past decade has been that growth in crude oil production has, at times, outpaced the availability of export pipeline capacity. Periods of constrained pipeline capacity relative to crude oil supply have contributed to periods where the price difference, or price differential, between crude oil prices in western Canada, such as Western Canadian Select (WCS), and benchmark international prices, such as West Texas Intermediate (WTI), has widened.

When export pipeline capacity is not constrained relative to crude oil supply, the differential typically reflects the cost to ship crude oil by pipeline and any differences in quality of crude oil types. In these circumstances, the WTI price is typically around US$12.50/bbl higher than WCS. During periods of tight pipeline capacity, the differential has widened to US$25/bbl or more, putting downward pressure on producer and government revenues. The expansion of the Trans Mountain system in 2024 helped alleviate tight pipeline capacity. Crude oil producers and shippers generally consider a cushion of spare export pipeline capacity to be beneficial, helping to avoid periods of tight capacity and high price differentials.

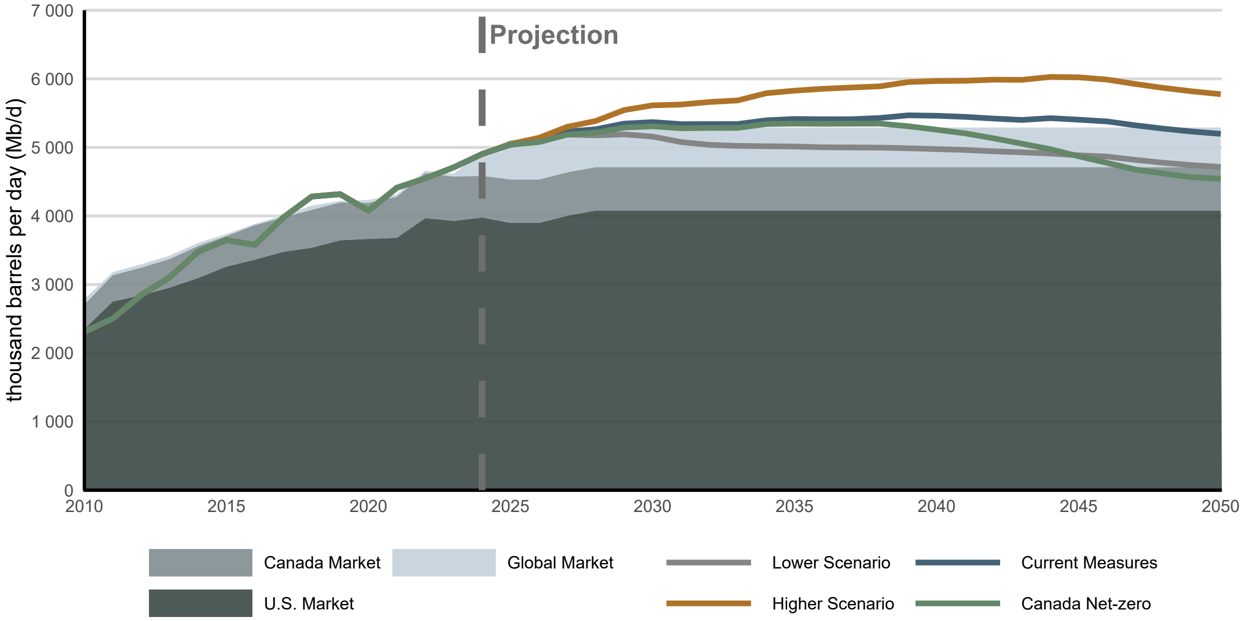
Projections—Western Canadian Crude Oil Available for Export

Figure S.8 is a simplified comparison of projected western Canadian crude oil supply available for export in all four scenarios and an illustrative level of total export capacity from existing pipelines, planned pipeline expansions, and structural rail. Crude oil available for export is defined as crude oil production in western Canada less the crude oil used in refineries in Alberta and Saskatchewan. It refers to crude oil available to be moved out of western Canada, whether it is moved to other parts of Canada, the U.S. or global markets. Crude oil available for export also includes diluent blended with both bitumen and heavy crude oil to facilitate their flow on pipelines. Only planned expansions for which companies have reached public final investment decisions by the end of November 2025 are included in Figure S.8. Importantly, inclusion here has no bearing on any regulatory approvals, including by the Commission of the CER, nor does it suggest any particular outcome of regulatory processes.

It is important to note that future available capacity could be higher or lower than reflected in Figure S.8. This is because projects that have not reached final investment decision or have not yet been announced are not included –such as additional expansions being considered to the Enbridge Mainline and Trans Mountain systems, or the pipeline project referenced in the Canada-Alberta Memorandum of Understanding (i.e. one or more pipelines with a route that increases export access to Asian markets as a priority). Also, currently existing pipelines could be decommissioned. As a result, a depiction of the crude oil available for export above, or below, the total capacity shown in Figure S.8 does not indicate the extent to which any existing or additional pipeline capacity would be utilized or not.

The Illustrative export capacity shown in the figure is segmented by the potential markets accessible through reliance on existing infrastructure and planned expansions for which companies have reached public final investment decisions. The U.S. portion of the figure represents only the capacity of pipelines shipping directly to the U.S. and excludes any potential exports reaching U.S. markets via marine vessels leaving Trans Mountain's Westridge marine terminal (rather, that capacity is all included in the global portion). Similarly, the global portion of the figure does not include any capacity to re-export Canadian crude oil from the U.S. Gulf Coast after moving on pipelines shipping directly to the U.S. In reality, some crude oil exported from the Westridge marine terminal is currently sent to costal refineries in the U.S., and Canadian crude oil is sometimes re-exported from the U.S. Gulf Coast. Appendix 4 describes the assumptions in Figure S.8 in more detail, specifically the assumptions underpinning the allocation of capacity to different markets.

Figure S.8: Illustrative export capacity, by potential market, from pipelines and structural rail vs. total supply available for export from western Canada, all scenarios[35,36]



The illustrative comparison in Figure S.8 can provide insight into whether pipeline constraints might affect crude oil production. We do not, however, adjust projected crude oil production or what we assume for western Canadian oil prices based on those potential constraints. For more information, see the "Accounting for producer and investor behaviour in production outlooks" textbox in the Results chapter.

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[35] For the purposes of Figure S.8, the "Global Market" portion of illustrative export capacity from pipelines and structural rail excludes capacity that may be able to deliver Canadian crude oil to global markets through the U.S. Gulf Coast.

[36] Some volumes shipped on Trans Mountain and moved by marine vessel are sent to the U.S. For the purpose of Figure S.8, all volumes that could be shipped by marine vessel are allocated to the "Global Market" because the option to ship to alternative markets exists.

Early in the projection period crude oil available for export in the Higher scenario exceeds the illustrative export capacity, with the gap reaching nearly 700 Mb/d later in the projection period. In Current Measures, volumes fluctuate around the same level as the illustrative capacity early in the projection period before rising above capacity for much of the remainder of the projection period, reaching as high as 178 Mb/d above illustrative capacity by 2039. In Canada Net-zero, crude oil available for export is similar to Current Measures and is slightly higher than capacity until about 2038, at which point it begins to fall below capacity. In the Lower scenario, crude oil available for export is below the illustrative capacity throughout the projection period. It is beyond the scope of this report to estimate the level of spare capacity in the pipeline system that would avoid material price reductions for western Canadian crude oil, whether on an ongoing basis or during events such as pipeline maintenance or market disruptions.

Trade Diversification

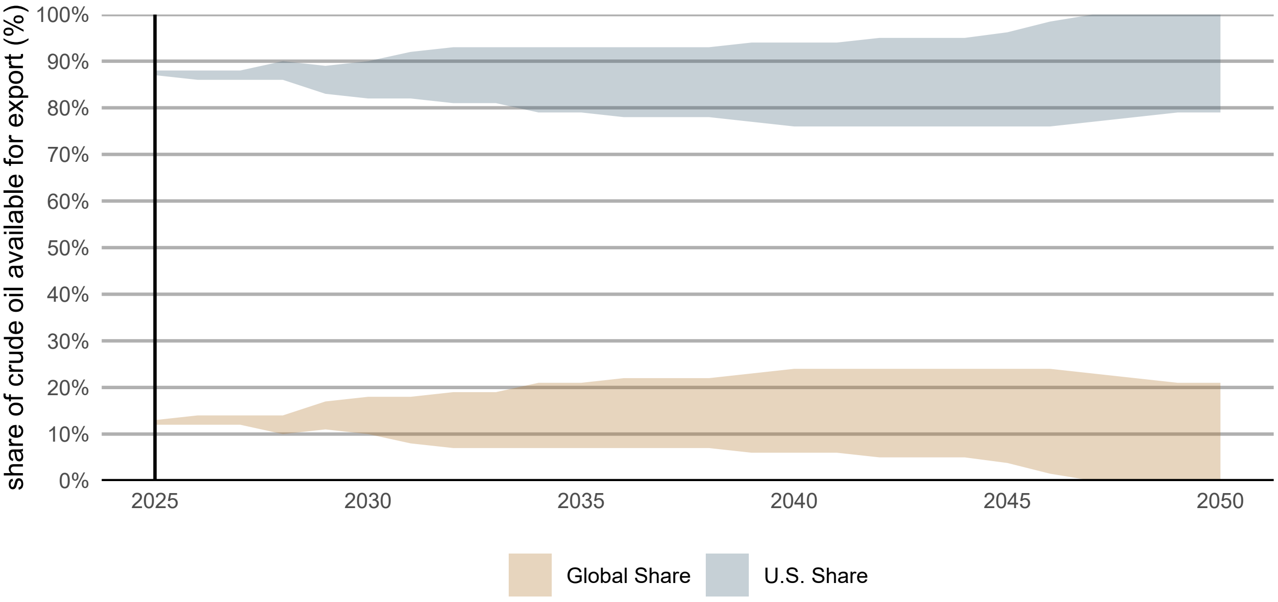
The extent to which Canada diversifies its crude oil trade will likely depend on a number of factors, including the destination and amount of any new pipeline capacity, the trajectory of future Canadian crude oil production, how existing flows of crude oil change over time, and future global trade policy shifts.

Figure S.9 builds on the illustrative comparison in Figure S.8 to explore implications for Canada's future crude oil trade diversification. Figure S.9 shows how the market share for Canadian crude oil exports—that is destined for the U.S. versus other global markets—could potentially change under the different oil production projections in our four scenarios. These shares are entirely illustrative—they aim to provide an isolated illustration of the minimum and maximum market shares that might result due specifically to crude oil production changes.

The shares in Figure S.9 are not meant to reflect *likely* outcomes. Nor are they the result of analyzing the drivers of pipeline flows such as transportation costs or contracts, downstream demand, and potential bottlenecks. Accordingly, the market share ranges in Figure S.9 are meant to provide an analytical starting point for considering future trade diversification, including if the future looked very different—such as if production were materially higher or lower than in our scenarios, or if major incremental pipeline capacity were added to a particular market. This analysis creates these potential ranges using the following methodology:

- When total crude oil available for export is above the illustrative export capacity (such as in certain periods for the Current Measures and Higher scenario):
  - The U.S. and global capacities shown in Figure S.8 are assumed to be fully utilized, and
  - The portion of volumes above total illustrative export capacity are either allocated completely to the U.S. market or completely to the global market.
- When total crude oil available for export is below illustrative export capacity (such as throughout the Lower scenario and later in the projection period in Canada Net-zero), we calculate the widest range of possible market shares (assuming export capacity as in Figure S.8) by:
  - In one case assuming full utilization of capacity to the global market at all times, such that any unutilized capacity is to the U.S. market, and
  - In the other case assuming full utilization of capacity to the U.S. market unless, and until, volumes to global markets would fall to zero, after which remaining volume reductions are taken from capacity to the U.S. market.
- Volumes of crude oil moving out of western Canada to other Canadian markets are kept at current levels.
- For simplicity, all volumes exported via the Westridge marine terminal are allocated to the global share, and all volumes exported via pipelines to the U.S. are allocated to the U.S. share. If some Westridge volumes went to the U.S. coastal refineries, the global share would be lower than in Figure S.9 (and the U.S. share would be higher). In contrast, if some volumes exported via pipelines to the U.S. were re-exported from the U.S. Gulf Coast, the global share would be higher than in Figure S.9 (and the U.S. share would be lower).

Figure S.9: Potential range of market share, global and U.S. markets, all scenarios



As shown in Figure S.9, there is a relatively narrow range in potential future market shares for the global and U.S. market under the assumptions of this analysis, and the U.S. continues to be the main market for Canadian crude oil exports. This is because so much Canadian crude oil transportation infrastructure is already destined for the U.S. market. Compared to any product or commodity widely shipped using more flexible methods like train, truck, or marine vessel, it is more challenging to shift Canadian crude oil exports to new markets due to the long-lived and fixed route nature of pipeline infrastructure.

In this illustrative analysis, the highest export market diversification occurs in the Higher scenario, when all the crude oil available for export over and above the illustrative pipeline capacity is assumed to go entirely to the global market. In this case, the share of western Canadian crude oil available for export with access to global markets grows from around 13% in 2025 to up to 25% later in the projection period.

The actual level of export market diversification of western Canadian crude oil could be higher or lower than shown in Figure S.9. Factors influencing actual diversification levels could include:

- Crude oil production could be higher or lower than in the scenarios in this report, increasing or decreasing the volume of crude oil available for export and the potential for trade diversification.
- Crude oil pipeline capacity could be expanded such that capacity is well above crude oil available for export. For example, if that additional capacity accesses global markets, it could potentially draw volumes away from the U.S. market, increasing trade diversification beyond what is reflected in Figure S.9.
- Some crude oil leaving the Westridge marine terminal could be delivered to U.S. coastal refineries, and some crude oil moving on U.S.-bound pipelines could be shipped to global markets from the U.S. Gulf Coast.

Summary

The vast majority of Canada's crude oil exports are destined for the U.S., as nearly all crude oil pipelines exiting western Canada deliver only to points in the U.S. The lack of diversity in export markets can make Canadian crude oil producers and the Canadian economy more vulnerable to disruptions.

While the comparison of export capacity to the volume of crude oil available for export from western Canada depicted in this section does not indicate the extent to which any existing or additional pipeline capacity would be utilized or not, it highlights a substantial range of potential outcomes. For example, in the Higher scenario, crude oil available for export exceeds available capacity, while in the Lower scenario it is lower than capacity throughout the projection period.

The analysis also indicates that with oil production as projected in our scenarios, there is somewhat limited potential to diversify Canada's crude oil trade. Diversification could be higher if crude oil production ends up being higher than in the scenarios in this report, which would lead to an increase in crude oil available for export and the potential to reach global markets. Greater diversification could also be realized if crude oil pipeline capacity to access global markets was expanded such that overall capacity is well above crude oil available for export in our scenarios, and that additional capacity draws volumes away from the U.S. market.

About the CER

The CER works to keep energy moving safely across the country. We review energy development projects and share energy information. We enforce some of the strictest safety and environmental standards in the world in a manner that respects the Government of Canada's commitments to the rights of Indigenous Peoples. The CER regulates:

- Oil & Gas Pipelines: Construction, operation, and abandonment of interprovincial and international pipelines and related tolls and tariffs.
- Electricity Transmission: Construction and operation of international power lines and designated interprovincial power lines.
- Exports & Energy Markets: Exports of certain energy products; monitoring aspects of energy supply, demand, production, development, and trade.
- Exploration & production: Oil and natural gas exploration and production activities in the offshore and on frontier lands not covered by an accord.
- Offshore renewables: Offshore renewable energy projects and offshore power lines in federal offshore areas that are not subject to one of the Atlantic Accord Acts[37].

The Energy Information Program is one of four core CER responsibilities. We collect, monitor, analyze, and publish fact-based information on energy markets and supply, sources of energy, and the safety and security of pipelines and international power lines. Using tools like interactive pipeline maps and visualizations, we make complex pipeline and energy market data user-friendly and accessible.

Our Commitment:

- Canadians have access to and use energy information for knowledge, research, and decision-making.
- Canadians have access to community-specific information about CER-regulated pipelines, power lines, and other energy infrastructure.
- Broader and deeper collaboration with stakeholders, rightsholders, and partners informs our energy information.

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[37] Atlantic Accord Acts refer to the Canada - Newfoundland and Labrador Atlantic Accord Implementation and Offshore Renewable Energy Management Act, and the Canada - Nova Scotia Offshore Petroleum Resources Accord Implementation, and Offshore Renewable Energy Management Act.

Appendix 1: Domestic Climate Policy Assumptions

Domestic climate policies include laws, regulations, and programs put in place by governments with the goal of reducing GHG emissions. Around 80% of Canada's GHG emissions are energy-related, so climate policies aimed at reducing emissions will affect Canada's energy system. We make assumptions about the climate policies we model in each scenario in this report. This appendix includes additional details about the climate policy assumptions to complement the overview in the Scenarios and Assumptions chapter.

Federal, provincial, and territorial climate policies that are currently in place are the basis of all four scenarios. A policy is "in place" if it was enacted prior to the end of November 2025. Table A1.1 provides an overview of all major federal policies included in all four scenarios. Table A2.2 provides an overview of key policies in provinces and territories.

In Canada Net-zero, to reach the predetermined goal of net-zero emissions by 2050, we assume that climate action increases beyond the policies that are currently in place. We do this on a sector-by-sector level, and the assumptions are informed by extending current policies and/or reflecting announced policies. Table A2.3 provides an overview of these assumptions. It is important to remember that these are assumptions for modeling purposes only and are not intended to be policy recommendations.

For an exhaustive review of climate measures in Canada, see Environment and Climate Change Canada's 2025 Progress Report on the 2030 Emissions Reduction Plan.

All dollar values are given in current Canadian dollars (C$2025), unless otherwise stated.

Table A1.1: Overview of major federal policies included in all scenarios

Policy	Description	Key assumptions used for modeling
Carbon pricing	All provinces and territories have an industrial carbon pricing system which provides an incentive to reduce emissions. The federal government sets minimum national standards for industrial carbon pricing systems. Most provinces and territories have their own system, while some use the federal output-based-pricing system. A similar framework for consumer carbon pricing was eliminated in early 2025.	We assume all systems increase their industrial carbon price in line with the federal benchmark by 2030 ($170 per tonne, nominal). This remains at this level in nominal terms for the remainder of the projection. Due to inflation the price trends to around $100 per tonne in 2025 Canadian dollars by 2050. For output based pricing systems, we assume tightening rates for emissions benchmarks in line with current federal legislation to 2030: 2% per year for most industries and 1% for high risk trade-exposed industries.

Policy	Description	Key assumptions used for modeling
Methane regulations for the upstream oil and gas sector	Oil and natural gas facilities are required to reduce their methane emissions either through adoption of new methane control technologies or process changes.	Facilities must reduce their methane emissions by 40-45% from 2012 levels by 2025.
Clean economy investment tax credits	Various investment tax credits that reduce clean technology costs. Includes CCUS, clean technology, clean hydrogen, clean electricity, and clean technology manufacturing.	We include these investment tax credits. At the time of modeling, the clean electricity ITC was not legislated but was committed to in Budget 2025. Our assumptions on the clean electricity ITC are based on draft legislation. In addition, the CCUS ITC extension in Budget 2025 is included.
Clean Electricity Regulations	The Clean Electricity Regulations set an annual emissions limit (AEL) (measured as tCO_2/year) for electric power generating units that burn any amount of fossil fuels. The AEL is technology neutral and determined based on the capacity of a given power-generating unit and an emissions performance standard set by the regulation. The operators of electricity generating units can choose a variety of compliance pathways for the regulations.	The Clean Electricity Regulations are included for all regions.
National energy code for buildings	Minimum energy efficiency standards for energy-using technologies in the residential, commercial, and industrial sectors (e.g. space air conditioning equipment, water heaters, household appliances, lighting).	Includes Amendment 17 to the Energy Efficiency Regulations. Energy efficiency gains end in 2030 and are carried through to 2050.
Hydrofluorocarbon (HFC) Regulation	A phase down of HFC consumption from a baseline.	An 85% reduction in consumption of HFCs by 2050 from 2019 levels.
Electric Vehicle Availability Standard	A regulated sales target for ZEVs that auto manufacturers and importers must meet.	We include the original legislated sales targets (including 60% by 2030 and 100% by 2035), except without the 2026 target given the pause announced in September 2025. In early February 2026, the Government of Canada announced that it would repeal the Electric Vehicle Availability Standard, in favour of other policies to encourage EV adoption. Our modeling is based on policies that were in-place November 2025, so it does not reflect these changes.

Policy	Description	Key assumptions used for modeling
Light-duty vehicle GHG emissions standards	New light-duty vehicles sold in Canada must meet progressively more stringent GHG emissions standards.	Incorporates LDV-1 (2011-2016) and LDV-2 (2017-2026) Light-duty vehicle GHG emission standards. New light-duty vehicle fuel economy improves approximately 5% per year from 2023 to 2026.
Heavy-duty vehicle GHG emission standards	New heavy-duty vehicles sold in Canada must meet progressively more stringent GHG emission standards.	Incorporates HDV-1 (2014-2018) and HDV-2 (2021-2027) heavy-duty vehicle GHG emission standards. New heavy-duty vehicle fuel economy improves approximately 2-3% per year from 2023 to 2027.
Clean Fuel Regulations	Reduction in carbon intensity of gasoline and diesel over time, through several mechanisms, including: -supplying low-carbon fuels (e.g. ethanol), -end-use fuel switching in transportation fuels (e.g. electric and hydrogen vehicles), and upstream projects (e.g. CCS).	Carbon intensity decrease of 12g CO_2e/MJ below 2016 levels by 2030.
Renewable Fuel Regulations	Minimum renewable fuel content for all regions except for Newfoundland and Labrador and the Territories.	Specifies a minimum renewable fuel content of 5% in gasoline and 2% in diesel fuel sold in Canada by volume.
Northern Responsible Energy Approach for Community Heat and Electricity (REACHE) program	Northern REACHE is a part of Wah-ila-toos.	We include Northern REACHE funds projects related to capacity building, renewable energy and energy efficiency projects. The program objective is to reduce Northern communities' reliance on diesel.

Table A1.2: Overview of the major provincial and territorial policies included in all scenarios

Region	Policy	Description
British Columbia	Zero Emissions Vehicle Act	Requires automakers to sell a minimum share of zero- or low-emission vehicles via a credit market, targeting 100% by 2035. This regulation is currently under review, and the BC government has said they will align to new federal standards (see Electric Vehicle Availability Standard in Table A1.1). Our modeling is based on policies that were in-place November 2025, so it does not reflect any pending changes.
	CleanBC Industry Fund	Government investment into low-emission technologies using a portion of carbon pricing revenue above \$30/tCO$_2$e to support competitiveness in industry.
	BC Energy Step Code	New homes will need to be built with more energy efficiency than current homes: compared to the 2018 BC Building Code requirements, 20 per cent more energy efficient by 2022, 40 per cent more energy efficient by 2027, 80 per cent more energy efficient by 2032 which is net-zero energy ready.
	Energy Efficiency Act	Sets energy efficiency performance standards for energy-using technologies.
	Low Carbon Fuel Standard	Requires a decrease in the average carbon intensity of 30% by 2030 from 2020 for transport fuels through several compliance pathways.
	Renewable Natural Gas Regulation	Requires that 15% of natural gas consumption be provided by renewable natural gas by 2030.
Alberta	Renewable Fuels Standard (RFS)	Requires a minimum blending 5% renewable alcohol in gasoline and 2% renewable diesel in diesel fuel.
	CCUS investments	Investments in CCUS projects, including the Alberta Carbon Trunk Line and Quest projects.
	Alberta Carbon Capture Incentive Program	Provides a grant of 12% for new eligible CCUS capital costs
	Methane emissions reduction regulation	Requires the reduction of methane emissions from oil and natural gas operations by 45% by 2025 relative to 2014 levels.
Saskatchewan	Ethanol Fuel Regulations and Renewable Diesel Act	Requires a minimum of 7.5% of ethanol content in gasoline and 2% biodiesel content in diesel.

Region	Policy	Description
	Methane Action Plan	Requires the reduction of methane emissions from oil and natural gas operations by 45% by 2025 relative to 2015 levels.
Manitoba	Biofuels Mandate amendment	Requires a minimum of 10% ethanol content in gasoline and 2% biodiesel content in diesel.
	Efficiency Manitoba Act	Rebates and other incentives on lighting, air conditioning, and building shell across residential, commercial, and some industrial sectors.
	Green Energy Equipment tax credit	A 15% tax credit on geothermal heat pumps in residential and commercial sectors.
Ontario	Cleaner Transportation Fuels: Renewable content requirements for gasoline and diesel fuels	A regulation requiring 15% ethanol content in gasoline and 4% biodiesel content in diesel by 2030.
Quebec	Western Climate Initiative cap-and-trade regime	A cap-and-trade system for industrial and electricity sectors, as well as fossil fuel distributors. Declining annual caps are set out to 2030 and the revenue generated by the policy is invested in low-carbon technologies. As caps are not set after 2030, the federal pricing systems (fuel charge and output-based pricing system) apply in our scenarios.
	Chauffez Vert Program	Rebates for residential renewable energy space or water heating systems, if replacing fossil fuel system. Financial assistance will end as of March 2026.
	Roulez Vert Program	Incentives for electric vehicles and charging station installations. There was a pause on this program from February 1st to March 31st 2025, with rebate amounts decreasing in 2025 and 2026, with an end date of 2027.
	Zero Emissions vehicle standard	Requires automakers to sell a minimum share of zero- or low-emission vehicles via a credit market. The credit target is 100% by 2040.
	Quebec Green Hydrogen and Bioenergy Strategy	Increase bioenergy production by 50% by 2030, 5% RNG in the grid by 2023 and a minimum of 10% by 2030.
New Brunswick	Energy efficiency programs	Provides purchase incentives for energy efficient appliances in residential, commercial, and industrial sectors.

Region	Policy	Description
Nova Scotia	EfficiencyNS Programs	Incentives for residential, commercial, transportation and some industrial sectors. Incentives include the transition from oil heating to electric, heat pumps, and charging stations.
Newfoundland and Labrador	Energy efficiency programs	Incentives for residential, commercial, and some industrial sectors. These programs include a home energy savings program, heat pump rebates, and commercial sector rebates for select appliances.
	Oil to Electric Incentive Program	Rebates for switching home heating from oil to electric
Prince Edward Island	EfficiencyPEI rebates	Incentives for residential, commercial, and some industrial sectors. Various rebates on energy-efficient appliances, like heat pumps, solar systems, biomass heating, and fuel-efficient furnaces.
	Rebates for electric vehicles	Rebates for BEVs up to $4000 and up to $2000 for PHEVs
	Rebates for commercial charging infrastructure	Charging infrastructure rebates for level 2 and fast chargers.
Northwest Territories	2030 Energy Strategy	Measures that aim to support low-carbon energy for transportation and space heating. Includes promoting the use of wood as an alternative source of energy to fossil fuels, supporting the development and implementation of community energy plans, incentives for energy efficiency and alternative energy projects, support for alternatives to diesel electricity generators, and rebates for zero- and low-emission vehicles.
Yukon	Our Clean Future	Measures including 10% ZEV new sales by 2025 and 30% by 2030, ZEV rebates, blending of renewable fuels into diesel and gasoline, energy efficiency incentives and regulations, and renewable energy projects for remote communities.
Nunavut	Renewable Energy Homeowner Grant	Rebate on renewable systems installed on homes

Table A1.3: Assumptions on increases to policies to reach net-zero by 2050 in Canada Net-zero

Policy	Description	Key assumptions used for modeling
Extended clean fuels regulations	The Clean Fuel Regulations are currently defined to incrementally reduce emission intensity to 2030 (see Table A1.1). In Canada Net-zero, we assume regulations are tightened to further reduce emission intensity after 2030.	The carbon intensity of gasoline and diesel decreases an additional 1.5gCO_2e/MJ per year from 2030 to 2050.
Aggregate cost of carbon	A hypothetical suite of policies, regulations, and programs in the 2030 to 2050 period represented by a carbon price that applies to industrial sectors with existing carbon pricing systems.	Starting at $0/t CO_2e (carbon dioxide equivalent) in 2030 and rising to $450 in 2050. In total, the effective carbon price for sectors that face is $550/t in 2050 when added to the industrial carbon price as described in Table A1.1. For output-based pricing systems, we assume gradual tightening rates for emissions post-2030 at the same rate as current legislation: 2% per year for most industries and 1% for trade-exposed industries.
Freight ZEV standard	A regulated sales target for medium and heavy-duty trucks. While there is no current legislation in this area, the concept of a zero-emission vehicle standard for freight vehicles is discussed in Canada's Action Plan for Clean On-Road Transportation.	Medium- and heavy-duty sales targets are 35% by 2030 and 100% by 2040, where feasible. At the time of analysis, these regulations were still under development. We made the simplifying assumption that 80% of sales met the threshold of "feasible" by 2040, and 95% by 2050.

Policy	Description	Key assumptions used for modeling
Marine and aviation	We assume an increasing requirement for low and non-emitting fuels for marine and aviation. Since regulations for these sectors are often linked to international standards, our assumptions are informed by international modeling on emission-reduction scenarios, such as the IEA World Energy Outlook, as well as Canadian strategies such as Canada's Aviation Climate Action Plan.	Marine transportation and aviation are supplied by 40-45% clean fuels (a mix of biofuels, hydrogen, and electricity) by 2050.
Net-zero buildings	We assume that new buildings reduce emissions by both improving energy efficiency performance and a rising requirement to adopt zero-emission technologies for their primary heating requirements (while still allowing for fossil fuel back-up when desired).	The building shell efficiency of the total residential sector stock improves 50% from 2021 to 2050, where the commercial sector improves 43%. Oil as a primary heating source in new residential and commercial buildings ends in 2030 and natural gas as a primary heating source ends in 2035. Oil and natural gas can be used as back up heat source in new buildings out to 2050. Renewable natural gas and hydrogen can be blended into the natural gas streams if economic conditions are favourable.
Enhanced Methane Regulations	We assume all provinces meet the methane reduction goal of the regulations.	Oil and natural gas sector methane emissions are reduced by 75% by 2030 relative to 2012 levels.
Agriculture	Based on a review of the literature, net-zero / sustainable agricultural practices are adopted to reduce emissions from enteric fermentation, manure management, and agricultural soils.	By 2050, non-energy agriculture emissions are 27% lower in Canada net-zero relative to Current Measures. About 90% of the decline in emissions is attributed to the adoption of net-zero/sustainable agriculture practices, rather than due to lower sector output.

Policy	Description	Key assumptions used for modeling
Landfill methane regulations	Objective is to reduce methane emissions from landfills to 50% below 2019's levels by 2050.	MSW landfill methane emissions are reduced by 50% below 2019 levels by 2030 (as per federal government projections), with reductions starting in 2027.
Offsets for remaining emissions	In Canada Net-zero, we assume that a robust system exists to allow providers of negative emissions (including direct air capture, bioenergy with CCS, various nature-based solutions and other carbon dioxide removal technologies) to be compensated for their removals at a rate equivalent to the aggregate cost of carbon.	Our negative emission values from the electricity and hydrogen producing sectors, as well as direct air capture, are driven by their techno-economic parameters in contrast to the aggregate cost of carbon assumption. We assume negative emission contributions from land-use change, nature-based solutions, and other emerging carbon dioxide removal technologies are equivalent to -166 MT by 2050 in Canada Net-zero.

Appendix 2: Technology Assumptions

Assumptions related to technologies are important drivers of our energy supply and demand results. Table A2.1 provides an overview of key technology assumptions that we use in Current Measures and Canada Net-zero. Technology cost reduction assumptions in the Higher and Lower scenarios are the same as Current Measures.

Table A2.1: Key Technology Assumptions (C$2025)

<table>
<tr><th colspan="2">Technology</th><th>Current Measures</th><th>Canada Net-zero</th></tr>
<tr><td colspan="4">Hydrogen Production</td></tr>
<tr><td rowspan="3">Hydrogen electrolysis ($/kW)[38]</td><td>2024</td><td colspan="2">3,062</td></tr>
<tr><td>2030</td><td>2,041</td><td>1,470</td></tr>
<tr><td>2050</td><td>1,531</td><td>1,164</td></tr>
<tr><td rowspan="3">Hydrogen NG with CCUS ($/kW) [39]</td><td>2024</td><td colspan="2">1,368</td></tr>
<tr><td>2030</td><td>1,333</td><td>1,300</td></tr>
<tr><td>2050</td><td>1,249</td><td>1,053</td></tr>
<tr><td colspan="4">Electricity</td></tr>
<tr><td rowspan="3">Electricity generation - On-shore wind ($/kW)[40]</td><td>2024</td><td colspan="2">1,994</td></tr>
<tr><td>2030</td><td>1,767</td><td>1,495</td></tr>
<tr><td>2050</td><td>1,530</td><td>1,196</td></tr>
<tr><td rowspan="3">Electricity generation - Utility scale solar ($/kW) [41]</td><td>2024</td><td colspan="2">2,039</td></tr>
<tr><td>2030</td><td>1,840</td><td>1,550</td></tr>
<tr><td>2050</td><td>1,255</td><td>938</td></tr>
<tr><td rowspan="3">Electricity generation - Natural gas with CCUS ($/kW)[42]</td><td>2024</td><td colspan="2">4,082</td></tr>
<tr><td>2030</td><td>3,854</td><td>3,797</td></tr>
<tr><td>2050</td><td>3,108</td><td>2,939</td></tr>
</table>

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[38] Source: CER Derived values based on IEA WEO 2024, Global Hydrogen Review 2025, and NETL Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies 2022

[39] Source: CER Derived values based on IEA WEO 2024, Global Hydrogen Review 2025, and NETL Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies 2022

[40] Source: CER Derived values based on NREL 2024 Annual Technology Baseline and USEIA 2024 Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies

[41] Source: CER Derived values based on NREL 2024 Annual Technology Baseline and USEIA 2024 Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies

[42] Source: CER Derived values based on NREL 2024 Annual Technology Baseline and USEIA 2024 Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies

<table>
<tr><th colspan="2">Technology</th><th>Current Measures</th><th>Canada Net-zero</th></tr>
<tr><td rowspan="3">Electricity generation - Nuclear SMR ($/kW) [43]</td><td>2024</td><td colspan="2">12,375</td></tr>
<tr><td>2030</td><td>12,375</td><td>12,375</td></tr>
<tr><td>2050</td><td>7,796</td><td>6,187</td></tr>
<tr><td colspan="4">Carbon dioxide removal</td></tr>
<tr><td rowspan="3">Direct air capture ($ per tonne levelized cost of capture)[44]</td><td>2024</td><td colspan="2">600</td></tr>
<tr><td>2030</td><td>520</td><td>500</td></tr>
<tr><td>2050</td><td>400</td><td>275</td></tr>
<tr><td colspan="4">Buildings</td></tr>
<tr><td rowspan="3">Residential air source heat pumps with electric backup ($/unit)[45]</td><td>2024</td><td colspan="2">13,353</td></tr>
<tr><td>2030</td><td>12,511</td><td>12,257</td></tr>
<tr><td>2050</td><td>10,827</td><td>9,973</td></tr>
<tr><td>Residential electric resistance heating ($/unit)[46]</td><td>2024 to 2050</td><td colspan="2">2,500</td></tr>
<tr><td>Residential natural gas furnace ($/unit)[47]</td><td>2024 to 2050</td><td colspan="2">5,657</td></tr>
<tr><td>Residential central air conditioning ($/unit)[48]</td><td>2024 to 2050</td><td colspan="2">7,191</td></tr>
<tr><td>Building shell</td><td>2024 to 2050</td><td>Efficiency of new buildings varies regionally from 20-50% by 2050 relative to 2024</td><td>Efficiency of new buildings improves 50-60% by 2050 relative to 2024</td></tr>
</table>

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[43] Source: CER Derived values based on NREL 2024 Annual Technology Baseline and USEIA 2024 Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies

[44] Source: CER Derived values based on EPRI 2021 US Regen Model

[45] Source: Various sources:

- Natural Resources Canada.
- Electric Power Research Institute. (2025). US REGEN Documentation.
- U.S. Energy Information Administration. (2023). Updated Buildings Sector Appliand and Equipment Costs and Efficiencies.

[46] Source: U.S. Energy Information Administration. (2023). Updated Buildings Sector Appliance and Equipment Costs and Efficiencies.

[47] Source: U.S. Energy Information Administration. (2023). Updated Buildings Sector Appliance and Equipment Costs and Efficiencies.

[48] Source: U.S. Energy Information Administration. (2023). Updated Buildings Sector Appliance and Equipment Costs and Efficiencies.

Technology		Current Measures	Canada Net-zero
Transportation			
Battery electric vehicle ($/vehicle)[49]	2024	49,174	
	2030	45,166	41,159
	2050	41,626	34,078
Gasoline vehicle ($/vehicle)[50]	2024 to 2050	39,175	
Battery electric heavy duty freight truck ($/vehicle)[51]	2024	460,474	
	2030	392,749	306,605
	2050	350,135	308,033
Hydrogen fuel cell heavy duty freight truck ($/vehicle)[52]	2024	338,175	
	2030	273,255	224,689
	2050	228,429	189,683
Diesel heavy duty freight truck ($/vehicle)[53]	2024 to 2050	162,241	
Heavy Industry			
Iron and steel: electric arc furnaces (EAF)	2024-2050	Some facilities transition from coal to EAF and from coal to direct reduced iron EAF.	
Hydrogen in steel production: Hydrogen direct reduced Iron (H2-Dri)	2024-2050	Assume technology is not available at scale.	Assume availability of technology at scale and adoption if economic conditions allow.
Aluminum production: Inert anodes	2024-2050	20% adoption of inert anodes.	20% adoption by 2030 and a linear incline to 100% by 2050.

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[49] Source: National Renewable Energy Lab. (2024). 2024 Transportation ATB.

[50] Source: National Renewable Energy Lab. (2024). 2024 Transportation ATB.

[51] Source: National Renewable Energy Lab. (2024). 2024 Transportation ATB.

[52] Source: National Renewable Energy Lab. (2024). 2024 Transportation ATB.

[53] Source: National Renewable Energy Lab. (2024). 2024 Transportation ATB.

Appendix 3: Comparison to EF2023

This appendix summarizes some of the key changes between Canada’s Energy Future 2026 and Canada’s Energy Future 2023 for Current Measures and Canada Net-zero. The Higher and Lower scenarios were not included in Canada’s Energy Future 2023.

Updated historical data and models

- This report is based on historical demand, supply, and emissions data current as of 2023-2024. EF2023 was based on data from 2020-2022.
- We have implemented the ERA5 global weather data as the basis for our electricity resource and hourly electricity demand results. For this report, we based our analysis on the 2021 weather year.
- Cost and performance data was updated to reflect latest data (see Appendix 2 for more details and references).
- Notable model updates include:
  - Improved consideration of economics in the CER’s natural gas and conventional-oil production models to better simulate effects of oil, gas, and NGL prices as well as climate policy (such as methane regulations) on future drilling.
  - Enhanced technology cost data and models.
  - Improved representation in the electricity system model to better represent the Clean Electricity Regulations.

Updated Assumptions

- Table A3.1 summarizes select energy market and technology assumptions in Canada’s Energy Future 2026 and Canada’s Energy Future 2023.

Table A3.1: Key assumptions in Canada's Energy Future 2026 and Canada's Energy Future 2023 for 2050

	Current Measures Canada's Energy Future		**Canada Net-zero Canada's Energy Future**		**Notes**
	2026	**2023**	**2026**	**2023**	
Global oil price (Brent, US$2025/bbl)	75	81.52	65	65.22	Current Measures prices reflect updated assessment of consensus outlooks and recent trends.
North American natural gas price (Henry Hub, US$2025/MMBtu)	5.25	4.78	4.00	2.83	
On-shore wind electricity (C$2025/kW)	1,530	1,886	1,196	1,813	Changes in electricity costs in *Canada's Energy Future 2026* include an updated historical baseline for data. In the case of solar, this has led to higher cost assumptions. We have also updated future trends from latest research and analysis, including NREL's 2024 Annual Technology Baseline.
Utility Scale solar electricity (C$2025/kW)	1,255	733	938	635	
Natural gas with CCUS electricity (C$2025/kW)	3,108	3,250	2,939	2,750	
Small modular reactor electricity (C$2025/kW)	7,796	7,085	6,187	8,043	

Results

Table A3.2 compares select results from Canada's Energy Future 2026 and Canada's Energy Future 2023 for 2050.

Table A3.2: Key results in Canada's Energy Future 2026 and Canada's Energy Future 2023 for 2050

<table>
<tr><th rowspan="3"></th><th colspan="4">Canada's Energy Future Current Measures</th><th colspan="4">Canada's Energy Future Canada Net-zero</th></tr>
<tr><th colspan="2">2026</th><th colspan="2">2023</th><th colspan="2">2026</th><th colspan="2">2023</th></tr>
<tr><th>2035</th><th>2050</th><th>2035</th><th>2050</th><th>2035</th><th>2050</th><th>2035</th><th>2050</th></tr>
<tr><td>Total crude oil production (MMb/d)</td><td>6.0</td><td>5.9</td><td>6.5</td><td>6.3</td><td>4.8</td><td>4.8</td><td>5.9</td><td>4.1</td></tr>
<tr><td colspan="9">Notes: Oil production in the Canada's Energy Future 2026 Current Measures scenario trends lower due to a lower outlook for conventional oil. In Canada Net-zero, stronger growth in oil sands leads to higher production in 2050.</td></tr>
<tr><td>Total natural gas production (Bcf/d)</td><td>24.4</td><td>27.2</td><td>18.1</td><td>21.4</td><td>23.2</td><td>20.9</td><td>16</td><td>11</td></tr>
<tr><td colspan="9">Notes: Natural gas production is higher in all Canada's Energy Future 2026 scenarios due to higher production in 2023 and 2024 than projected in Canada's Energy Future 2023, and updated datasets and models. Canada Net-zero also includes a higher assumed natural gas price (Table A3.1)</td></tr>
<tr><td>Total electricity generation (TWh)</td><td>800</td><td>975</td><td>815</td><td>972</td><td>872</td><td>1,323</td><td>937</td><td>1,360</td></tr>
<tr><td colspan="9">Notes: Electricity generation is similar in Canada's Energy Future 2026 and Canada's Energy Future 2023. Some changes are related to new policies, updated historical data and assumptions.</td></tr>
<tr><td>Total end-use energy demand (PJ)</td><td>11,818</td><td>12,637</td><td>12,178</td><td>12,630</td><td>11,220</td><td>10,790</td><td>11,268</td><td>10,024</td></tr>
<tr><td colspan="9">Notes: End-use demand is similar in Canada's Energy Future 2023 and Canada's Energy Future 2026. Some changes are related to new policies, updated historical data and assumptions.</td></tr>
<tr><td>Net GHG emissions (megatonnes CO_2e)</td><td>562</td><td>546</td><td>582</td><td>566</td><td>427</td><td>0</td><td>344</td><td>0</td></tr>
<tr><td colspan="9">Notes: In Current Measures, emissions are similar in Canada's Energy Future 2023 and Canada's Energy Future 2026. In Canada Net-zero, emissions are higher in 2035, implying a more rapid reduction in the latter part of the projection to reach net-zero.</td></tr>
</table>

Appendix 4 – Detailed Assumptions for Figure S.8

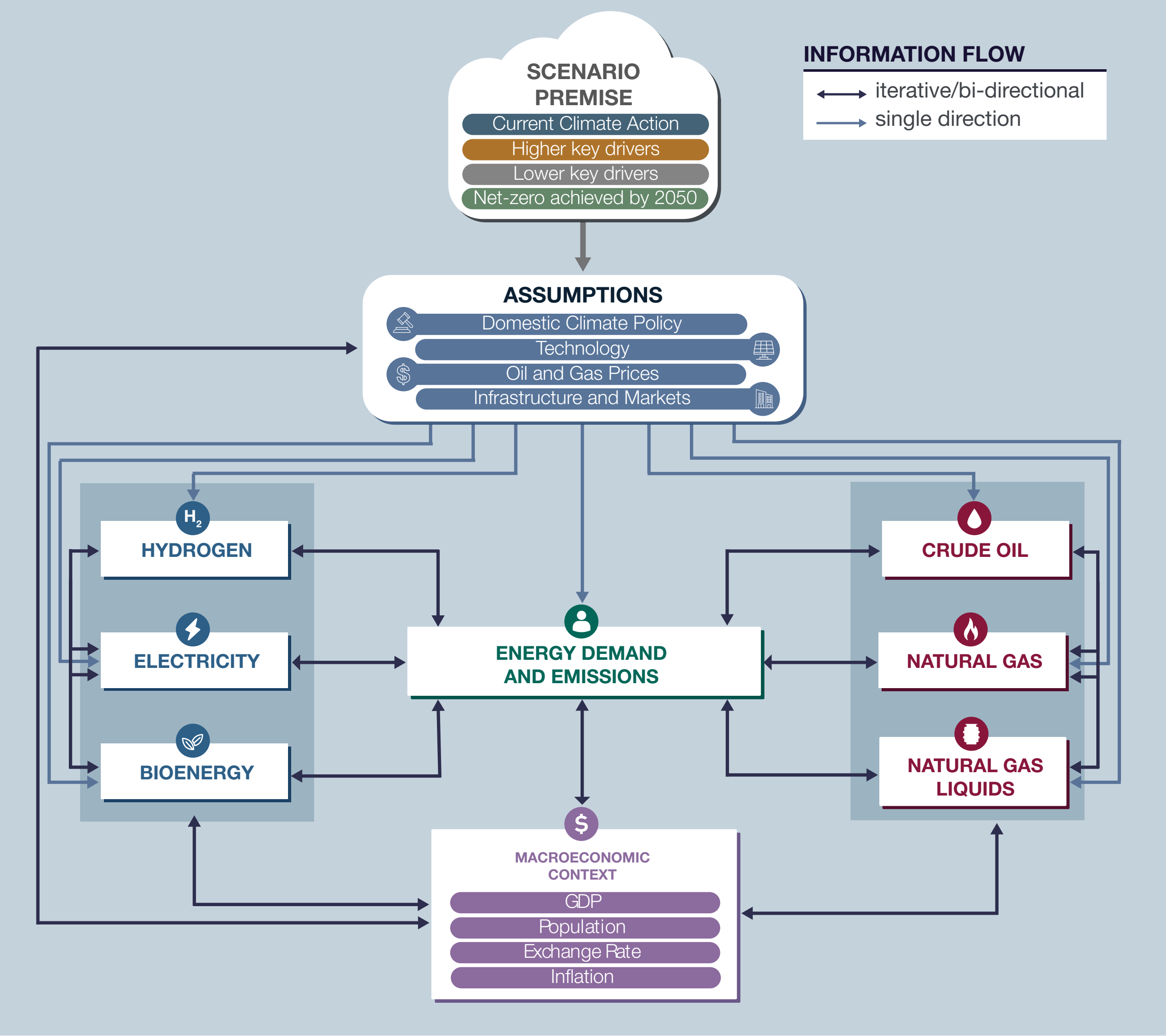
Illustrative Export Capacity from Pipelines and Structural Rail vs. Total Supply Available for Export from Western Canada, All Scenarios

Market	Illustrative Export Capacity from Pipelines and Structural Rail Assumptions
Canadian	Total (2025 to 2050): 633 Mb/d. This total includes the following: 586 Mb/d – Average monthly throughput (751 Mb/d) from October 2024 to September 2025 into Sarnia, Ontario on the Enbridge Mainline System, less 103 Mb/d to account for crude oil produced in the U.S. flowing on the system over that period and 62 Mb/d, an estimate of the volume of NGLs on the system reaching Sarnia. 47 Mb/d – Throughput from October 2024 to September 2025 on the Trans Mountain System delivered to the Burnaby Refinery in B.C.
U.S.	Total in 2025: 3,897 Mb/d, increasing to 4,077 Mb/d by 2028 and remaining at that level to 2050. This total includes the following: 2,528 Mb/d – Available capacity (3227 Mb/d) on Enbridge Mainline System at the Canada/U.S. border in Manitoba from October 2024 to September 2025, less: 586 Mb/d allocated to Canada noted in the previous row of this table, 33 Mb/d to account for crude oil produced in North Dakota that enters the system in Canada, and 80 Mb/d which is an estimate of the volume of NGLs on the system reaching the Canada/U.S. border in Manitoba. Capacity is increased by 150 Mb/d in 2027 to reflect Enbridge's planned Mainline Optimization Phase 1 expansion. 217 Mb/d – Throughput on the Trans Mountain System to the Sumas delivery point for delivery to refineries in Washington State from October 2024 to September 2025. 622 Mb/d – Nominal capacity on Keystone Pipeline. 453 Mb/d – Combined estimated capacity on Express, Milk River and Aurora/Rangeland. The capacity of Express increases by 30 Mb/d in 2027 to reflect a planned expansion. 77 Mb/d – Estimate of structural rail based on average crude-by-rail exports from November 2024 to October 2025. Structural rail represents crude-by-rail volumes that persist independent of price differentials, due to lack of pipeline connectivity for certain producers in Canada or refineries in the U.S.
Global	Total (2025 to 2050): 579 Mb/d – Available capacity of the Trans Mountain system from October 2024 to September 2025, less: 217 Mb/d of crude oil throughputs at Sumas, 47 Mb/d of crude oil throughputs at Burnaby, and 44 Mb/d total throughput of RPPs (each from October 2024 to September 2025). This total represents the potential volumes from the Westridge marine terminal. All volumes exported via the terminal have access to non-U.S. global markets via marine vessel. In reality, a portion of crude oil exported by marine vessel from the terminal is currently sent to the U.S. west coast.

Appendix 5: The Energy Futures Modeling System

The Canada's Energy Future series explores how possible energy futures might unfold for Canadians over the long term. We use economic and energy models to explore how supply and demand for energy could evolve. Figure A5.1 outlines the modelling system in a simplified diagram. These models start with a set of input assumptions which are based on the scenario that we are modeling and interact by passing key pieces of information back and forth to ensure a consistent set of projections. The results in Canada's Energy Future 2026 are not predictions about the future. Rather, they are the product of stylized scenarios based on a specific premise and set of assumptions.

Figure A5.1: Overview of the Canada's Energy Futures Modeling System



Energy Demand and Emissions

The demand projections are developed using the ENERGY2020 model: a hybrid energy-economy model created by Systematic Solutions Incorporated. It simulates how capital stocks of energy supply and demand technologies change over time in response to many factors, including economic activity, energy prices, household and business decision-making, and climate policy. It incorporates many types of historical data, such as energy supply and demand, technology and market characteristics, energy prices, and consumer preferences, and then creates projections on how the energy system evolves under different scenarios. A key driver of energy use projections is macroeconomic trends, such as population and economic growth. These trends are provided by an external macroeconomic expert, Stokes Economics, who creates custom economic projections that are consistent with our energy and emission assumptions and results.

Electricity

The electricity projections are created using a CER developed model. The core model is developed based on Python for Power System Analysis (PyPSA), an open-source, electric power system planning and simulation model. The CER model simulates how the future electricity demand of different Canadian economic sectors is satisfied by a combination of electricity-generating units and delivery systems. It models electricity-generating and storage units (including their technical and economic attributes), electricity transmission infrastructure, energy resource availability, electricity demand, and applicable regulations. The model simulates the operation of electric power systems at hourly intervals.

Crude oil

This CER-developed model provides crude oil production projections for the various regions and crude types in Canada, based on our price assumptions and other factors, such as carbon pricing and technological improvements. It includes an oil sands module, a non-oil sands deliverability module for western Canada, and analysis of other regions in Canada including east coast offshore.

Natural Gas

This CER developed model estimates the production of natural gas throughout Canada. It relies upon oil and natural gas price assumptions, LNG export assumptions, crude oil production estimated from the oil supply module, and other factors like technological change and policies. The module includes the Western Canadian Sedimentary Basin natural gas deliverability model, as well as trend analysis for other producing regions (e.g. New Brunswick).

Natural Gas Liquids

This CER developed model module provides estimates of NGL supply and demand in Canada. The module simulates various categories of liquids: ethane, butane, propane, condensate, and pentanes plus. For each liquid, the module provides estimates of production and supply and demand at the provincial or territorial level.

Hydrogen

This CER-developed model, which is based on PyPSA, determines low and non-emitting hydrogen production by technology type, based on domestic demand and export assumptions. The production technology choice is largely based on relative costs of the technology. Costs are based on the specific characteristics of each production technology, including capital costs, fuel use, capacity, access to carbon sequestration (if applicable), and emissions profiles.

Bioenergy

This CER-developed model estimates bioenergy supply by considering over 30 different biomass feedstocks and optimizes feedstock use for different bioenergy types in each province. The feedstock used for each bioenergy type depends on several things, such as feedstock suitability and availability, demand and price of the biofuels, preprocessing requirements, required land use, and production technology.

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