Canada Energy Regulator
Régie de l'énergie du Canada

Canada's Energy Future 2021

Canada

Permission to Reproduce

Materials may be reproduced for personal, educational and/or non-profit activities, in part or in whole and by any means, without charge or further permission from the Canada Energy Regulator, provided that due diligence is exercised in ensuring the accuracy of the information reproduced; that the Canada Energy Regulator is identified as the source institution; and that the reproduction is not represented as an official version of the information reproduced, nor as having been made in affiliation with, or with the endorsement of the Canada Energy Regulator.

If a party wishes to rely on material from this report in any regulatory proceeding before the CER, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material.

This report does not provide an indication about whether any application will be approved or not. The Commission will decide on specific applications based on the material in evidence before it at that time.

For permission to reproduce the information in this publication for commercial redistribution, please e-mail: info@cer-rec.gc.ca

Canada’s Energy Future 2021: Energy Supply and Demand Projections to 2050
PDF: NE2-12E-PDF
Paper: NE2-12E

ISSN 2562-069X (Print)
ISSN 2292-1710 (Electronic)
Key title: Canada's Energy Future

This report is published separately in both official languages.
This publication is available upon request in multiple formats.

Autorisation de reproduction

Le contenu de cette publication peut être reproduit à des fins personnelles, éducatives et(ou) sans but lucratif, en tout ou en partie et par quelque moyen que ce soit, sans frais et sans autre permission de la Régie de l'énergie du Canada, pourvu qu’une diligence raisonnable soit exercée afin d’assurer l’exactitude de l’information reproduite, que la Régie de l'énergie du Canada soit mentionnée comme organisme source et que la reproduction ne soit présentée ni comme une version officielle ni comme une copie ayant été faite en collaboration avec la Régie de l'énergie du Canada ou avec son consentement.

Quiconque souhaite utiliser le présent rapport dans une instance réglementaire devant la Régie peut le soumettre à cette fin, comme c’est le cas pour tout autre document public. Une partie qui agit ainsi se trouve à adopter l’information déposée et peut se voir poser des questions au sujet de cette dernière.

Le présent rapport ne fournit aucune indication relativement à l’approbation ou au rejet d’une demande quelconque. La Régie étudie chaque demande en se fondant sur les documents qui lui sont soumis en preuve à ce moment.

Pour obtenir l’autorisation de reproduire l’information contenue dans cette publication à des fins commerciales, faire parvenir un courriel à : info@cer-rec.gc.ca

Avenir énergétique du Canada en 2021 - Offre et demande énergétiques à l’horizon 2050
PDF : NE2-12F-PDF
Papier : NE2-12F

ISSN 2562-0703 (version imprimée)
ISSN 2292-1729 (version électronique)
Titre clé : Avenir énergétique du Canada

Ce rapport est publié séparément dans les deux langues officielles.
On peut l'obtenir sur supports multiples, sur demande.

Table of Contents

Introduction

Current Policies Scenario: A new name for the Reference Scenario

In EF2021, we have renamed one of the core scenarios of the Canada's Energy Future series. The "Current Policies Scenario" shares the same premise as the "Reference Case" or "Reference Energy System Scenario" in past versions of the report. We changed the name to "Current Policies" to increase clarity and be more explicit about the assumptions of the scenario: that it models only energy and climate policies that are currently in place. This change also clarifies that the scenario is not meant to be a most-likely or base-case scenario. EF scenarios provide alternative views on how the energy system could evolve in Canada given different inputs and assumptions.

Canada's Energy Future 2021: Energy Supply and Demand Projections to 2050 (EF2021) 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. We use economic and energy models to make these projections. The CER bases our projections on assumptions about future trends in technology, energy and climate policies, energy markets, human behaviour, and the structure of the economy.

EF2021 includes two core scenarios: The Evolving Policies Scenario and the Current Policies Scenario. The central difference between these scenarios is the level of future climate action, both globally and domestically. In both scenarios we provide projections for all energy commodities and all provinces and territories.

EF2021 also includes six additional electricity scenarios that explore what Canada's electricity system might look like in a net-zero[1] world. These scenarios focus only on how Canada will meet given electricity demands under different conditions, and do not include projections for other energy commodities. Electricity is an important contributor to achieving net-zero emissions, so these projections are an important step in modeling related to a net-zero energy system in the *Canada's Energy Future* series.

The analysis and projections for EF2021 are based on several important assumptions, outlined for the core scenarios in the "Scenarios and Assumptions" section of the report. The "Results" section provides an overview of our core scenario projections for various parts of the Canadian energy system to 2050, focusing on the Evolving Policies Scenario. The "Towards Net-Zero" section explores what Canada's electricity system could look like in a net-zero world, including assumptions and projections. Finally, the "Access and Explore Energy Futures Data" section provides links to access data, tools, and interactive data visualizations that offer further insight into EF2021.

1 Net-zero GHG emissions refers to the concept of balancing human-caused GHG emissions with removals from the atmosphere. See the text box "What is "Net-Zero"?" in the Towards Net-Zero section for more information.

Executive Summary

Overview and Background

The *Canada's Energy Future* series explores how possible energy futures might unfold for Canadians over the long term. *Canada's Energy Future 2021: Energy Supply and Demand Projections to 2050* (EF2021) is our latest long-term energy outlook. The outlook covers all energy commodities and all Canadian provinces and territories, and makes projections using economic and energy models. We also make assumptions about technology, energy and climate policies, energy markets, human behaviour, and the economy.

In the long term, global and Canadian ambition to reduce greenhouse gas (GHG) emissions will be a critical factor in how energy systems evolve. EF2021 considers two main scenarios, where energy supply and demand projections differ based on the level of future action[2] to reduce GHG emissions. EF2021 also includes six additional scenarios that explore what Canada's electricity system might look like in a net-zero world. The two main scenarios include projections for all energy commodities, whereas the six electricity scenarios focus only on how Canada will meet given electricity demands under different conditions.

The first main scenario in EF2021 is the Evolving Policies Scenario. The premise of this scenario is that action to reduce GHG emissions from our energy system continues to increase at a pace similar to recent history, in both Canada and the world. Relative to a scenario with less action to reduce GHG emissions, this projection implies less global demand for fossil fuels, and greater use of low-carbon technologies. The second main scenario is the Current Policies Scenario, which assumes limited action to reduce GHGs beyond policies in place today.

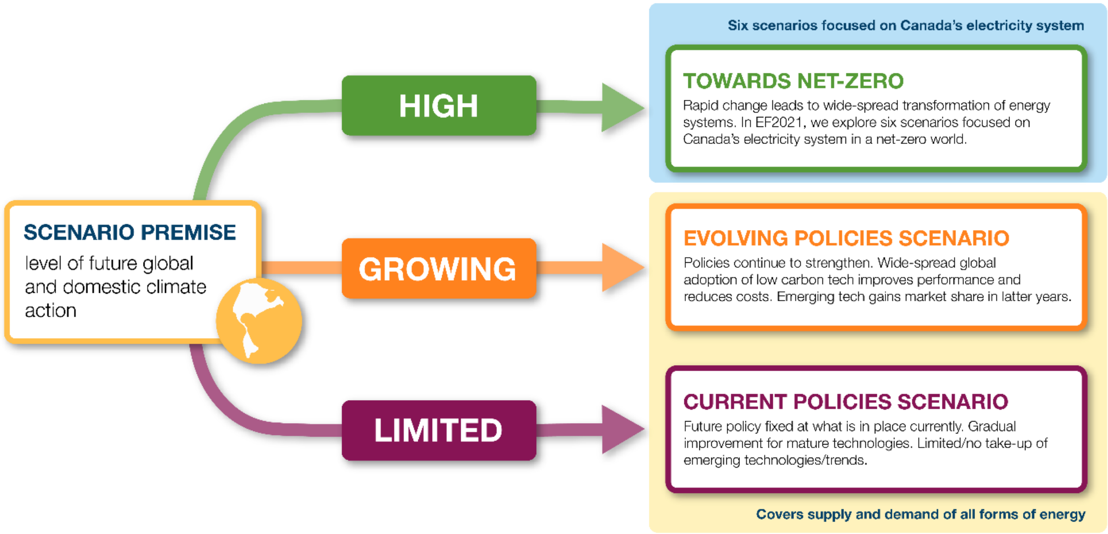
These scenarios do not explicitly model climate goals or targets. Instead, we make assumptions based on the scenario premises and rely on the Energy Futures Modelling Framework to make long-term projections of energy supply and demand in Canada. Together, these scenarios provide insights into what the energy system might look like if action to reduce GHG emissions continues to grow at the pace it has in recent years, or if it were to stop at current levels.

Canada has committed to reducing its GHG emissions by 40 to 45% below 2005 levels by 2030 and achieving net-zero GHG emissions by 2050. Reducing emissions to these levels will likely require more change than we model in the Evolving or Current Policies scenarios. Therefore, EF2021 introduces six new scenarios that explore a net-zero future. Specifically, these scenarios explore what Canada's electricity system might look like in a net-zero world under different assumptions about future technologies, climate policies, and electricity use. Electricity is expected to be an important contributor to achieving net-zero emissions, so these projections are an important step in modeling related to a net-zero energy system in the *Canada's Energy Future* series.

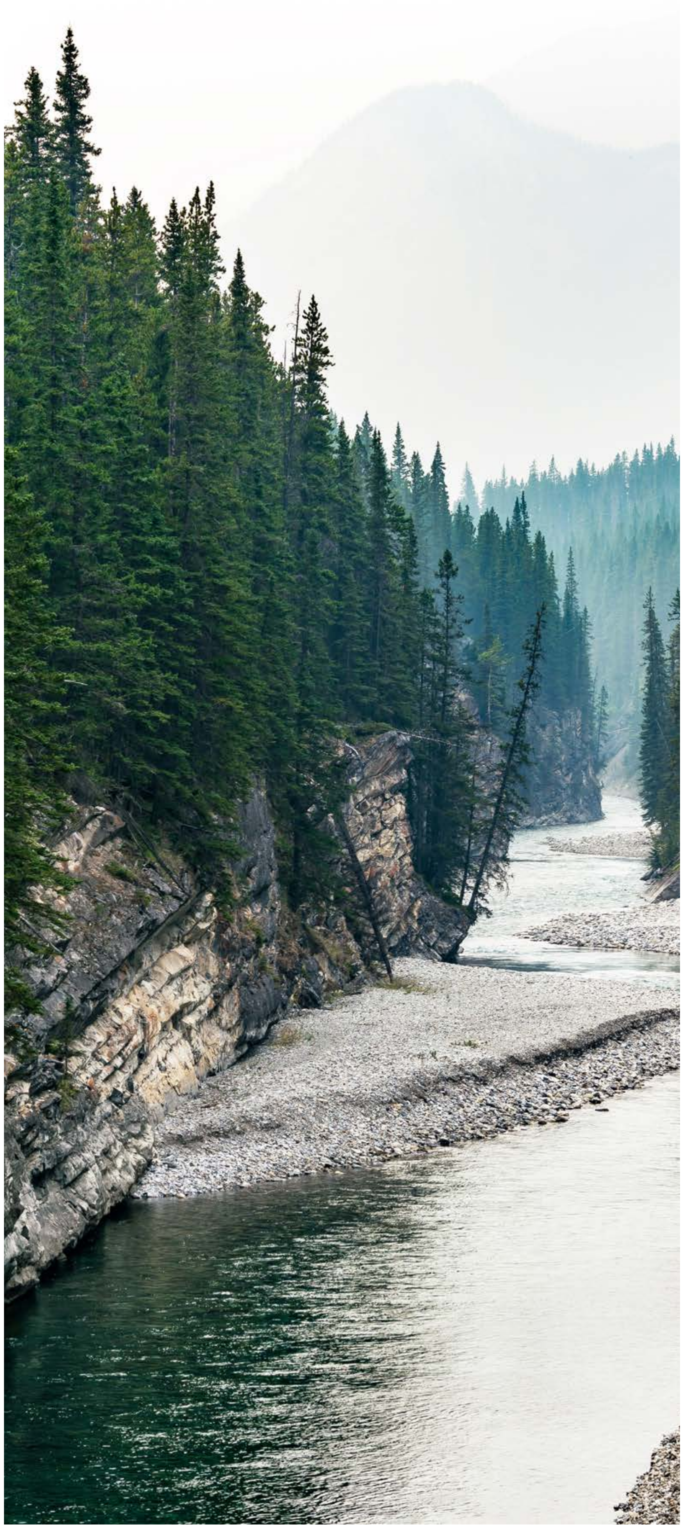
Figure ES.1 provides a conceptual illustration of the two main scenarios included in EF2021, as well as the net-zero scenarios focused on electricity.

[2] "Action" in this context is led by increasing policies, while also considering behavioural decisions by consumers and firms.

Figure ES.1:
Conceptual Illustration of EF2021 Scenarios



This Executive Summary highlights the key findings of EF2021. The "Scenarios and Assumptions" section outlines the specific assumptions used in the Evolving and Current Policies scenarios. The "Results" section provides an overview of the projections for the various parts of the Canadian energy system under our two main scenarios, with a focus on the Evolving Policies Scenario. The "Towards Net-Zero" section includes the first major net-zero modeling exercise of the *Canada's Energy Future* series: six scenarios that examine the effect of different factors (e.g. technology, policies, level of electrification, infrastructure) on Canada's electricity system in a net-zero world. Finally, the "Access and Explore Energy Futures Data" section provides links to access data, tools, and interactive data visualizations for further exploration of EF2021.



Key Findings

1. In the Evolving Policies Scenario, combustion of fossil fuels whose emissions are not captured falls 62% from 2021 to 2050, while use of low and non-emitting energy sources increases. While this implies a significant reduction in GHG emissions by 2050, achieving net-zero will likely require more change than is included in this scenario.

In the Evolving Policies Scenario, Canadians reduce their energy consumption and adopt lower carbon sources (Figure ES.2). Total primary energy use falls 21% from 2021 to 2050 as energy efficiency improves. Low and non-emitting sources–including renewables, nuclear, and fossil fuels with carbon-capture and storage (CCS)–grow to make up the strong majority of energy use. Unabated fossil fuel combustion (fossil fuel combustion without CCS) falls 19% from current levels by 2030, 45% by 2040, and 62% by 2050 (Figure ES.3).

Policy assumptions in the Evolving Policies Scenario are based on strengthening or expanding existing global and domestic policies at a pace consistent with recent trends. The Evolving Policies Scenario projections show significant changes in Canada's energy system and imply large reductions in GHG emissions. However, given the remaining unabated fossil fuel demands in 2050, the Evolving Policies Scenario also signals the need for greater long-term change in order to reach Canada's target of net-zero emissions by 2050. In addition to policy, many other factors we discuss in EF2021–such as global energy markets, technology, and consumer behaviour and preferences–will also influence future Canadian energy and emission trends.

Figure ES.2:
Total Canadian Energy Use, Evolving Policies Scenario

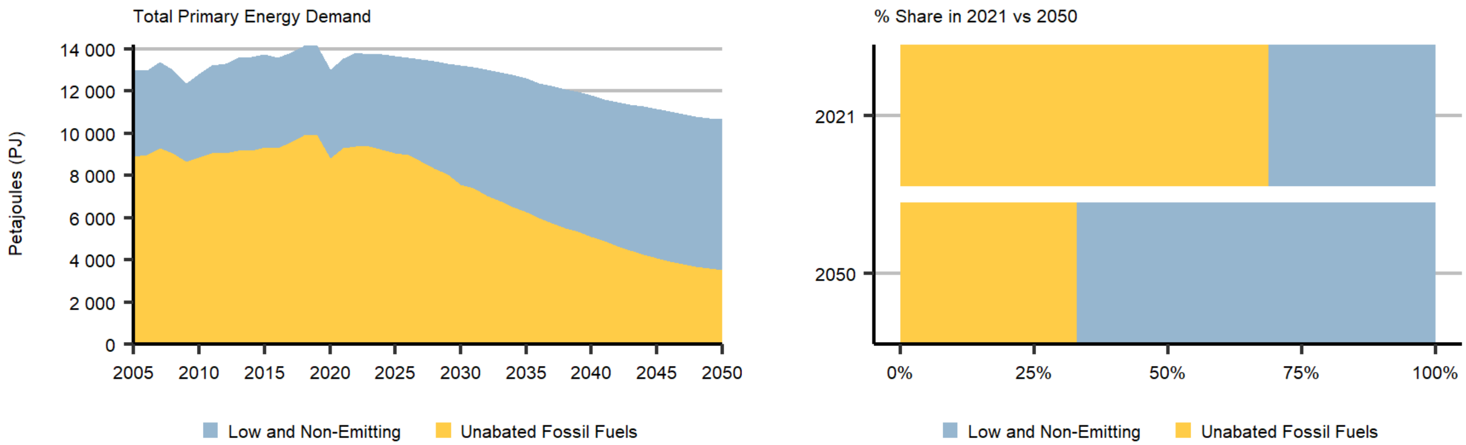
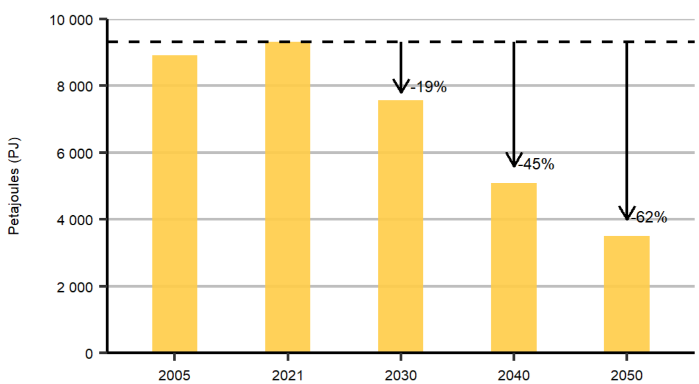


Figure ES.3:
Total Canadian Energy Use, Evolving Policies Scenario



2. Canadians use more electricity, from increasingly low-carbon sources. Despite total energy use declining, electricity demand grows 47% from 2021 to 2050 in the Evolving Policies Scenario, much of it from new areas such as electric vehicles and hydrogen production. Canada's electricity system also gets greener, going from 82% low and non-emitting in 2021 to 95% in 2050.

Compared to the past two decades when electricity use grew very slowly, electricity demand grows quickly over the projection period in the Evolving Policies Scenario. This increase is driven by increased electrification of the energy system. Total electricity demand increases by 47% from 2021 to 2050, or by about 263 terawatt hours (TWh) (Figure ES.4). Half of this increase is driven by increased electrification in the industrial, residential, and commercial sectors. The other half comes from electric vehicles in transportation and the production of hydrogen. In particular, by 2050, electric vehicles dominate Canada's vehicle mix and increase electricity demand by 70 TWh. This results from the Evolving Policies Scenario assuming nearly all new passenger vehicles sold in 2035 are battery or plug-in hybrid electric vehicles.

As demand grows, Canadian electricity generation increases. Wind and solar generation provide much of this additional electricity over the projection period, given their low cost. Natural gas generation is increasingly equipped with CCS. Low and non-emitting electricity generation make up 82% of total generation in 2021, rising to 88% by 2030, 94% by 2040, and 95% by 2050.

Figure ES.4:
Electricity Demand by Sector, Evolving Policies Scenario

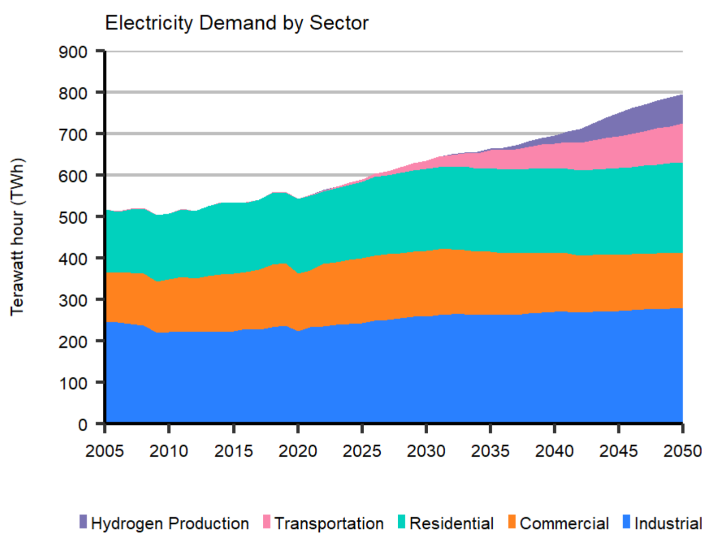
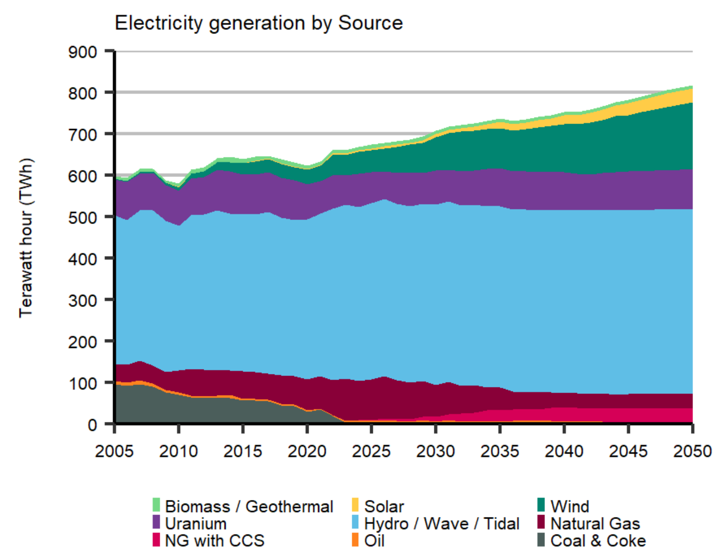


Figure ES.5:
Electricity Generation by Source, Evolving Policies Scenario

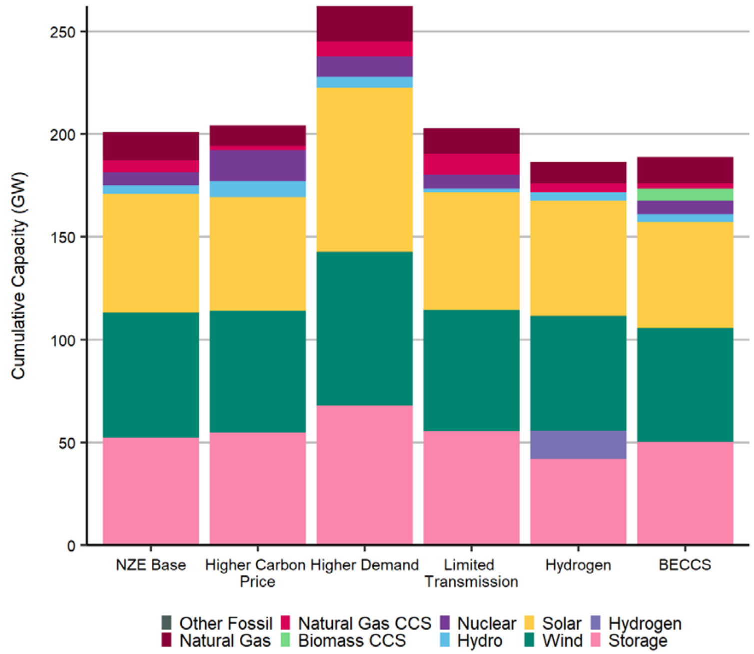


3. Wind, solar, and battery storage dominate electric capacity additions in all six net-zero electricity scenarios, making up between 82-85% of added capacity. With rising levels of wind and solar, all scenarios require flexible generation sources to balance supply and demand. There are large differences in the types and capacities of flexible generation sources adopted among scenarios.

The net-zero electricity scenarios each have a unique set of assumptions that examine many factors including technology, policies, level of electrification, and infrastructure. Figure ES.6 shows the net capacity additions for all six scenarios from 2019 to 2050. Consistent across all scenarios are large additions of wind and solar capacity, ranging from 100 gigawatts (GW) to 150 GW. These technologies are increasingly adopted due to their assumed low future costs in all scenarios. With large amounts of wind and solar capacity, power systems require additional flexible generating resources to balance supply and demand (given the variability of wind and sun conditions). Across the net-zero scenarios, the flexible generating resources are a combination of battery storage, natural gas-fired generation (with and without CCS), small modular nuclear reactors, hydropower, hydrogen-fired generation, biomass-fired generation with CCS, and transmission between provinces. The relative share of these flexible resources varies significantly across the scenarios, though the role of storage in balancing the grid increases dramatically in all scenarios.

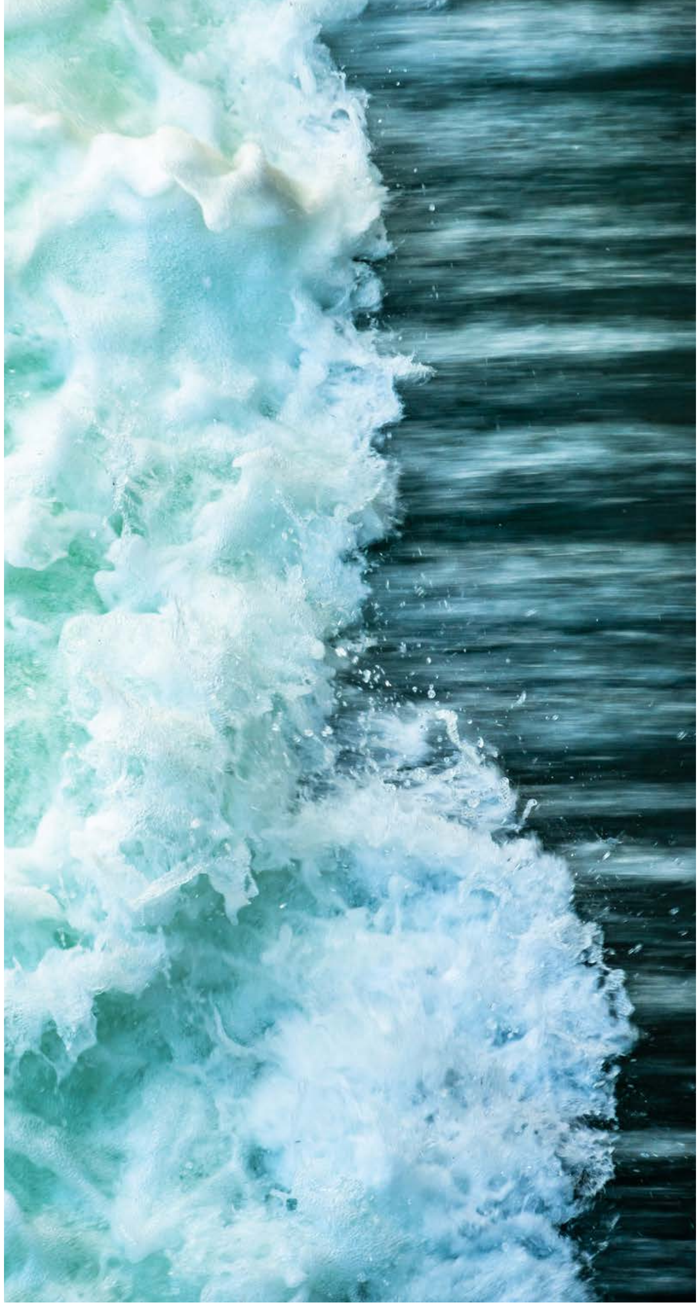
Figure ES.6:

Cumulative Capacity Additions to 2050, All Net-Zero Electricity Scenarios



Electricity Emissions in a Net-Zero World

In these scenarios, the emissions from the electricity sector drops dramatically, but a very small amount of emissions remains from natural gas-fired plants in five of the six scenarios. We allow these emissions because the value of these facilities in terms of electricity system reliability and stability is high. This allowance reflects that, in the context of a broader net-zero world, the use of carbon removal options could potentially provide more cost-effective options than reducing those last few emissions from the electricity system in 2050.



4. The net-zero electricity scenarios suggest that Canadian power systems will continue to be very distinct across the country, even in a low-carbon future. In each net-zero electricity scenario, the ten provinces meet their electricity demands in diverse ways, with widely varying mixes of hydro, nuclear, fossil fuel with CCS, wind, solar, hydrogen, and biomass with CCS.

Figure ES.7 shows the generation mix for each province in the main net-zero electricity scenario. In British Columbia (B.C.), Manitoba, Quebec, and Newfoundland and Labrador, electricity generation continues to be primarily hydropower. Nuclear power remains limited to Ontario and New Brunswick and represents about 41% and 24%, respectively, of those provinces' electricity supply in 2050.

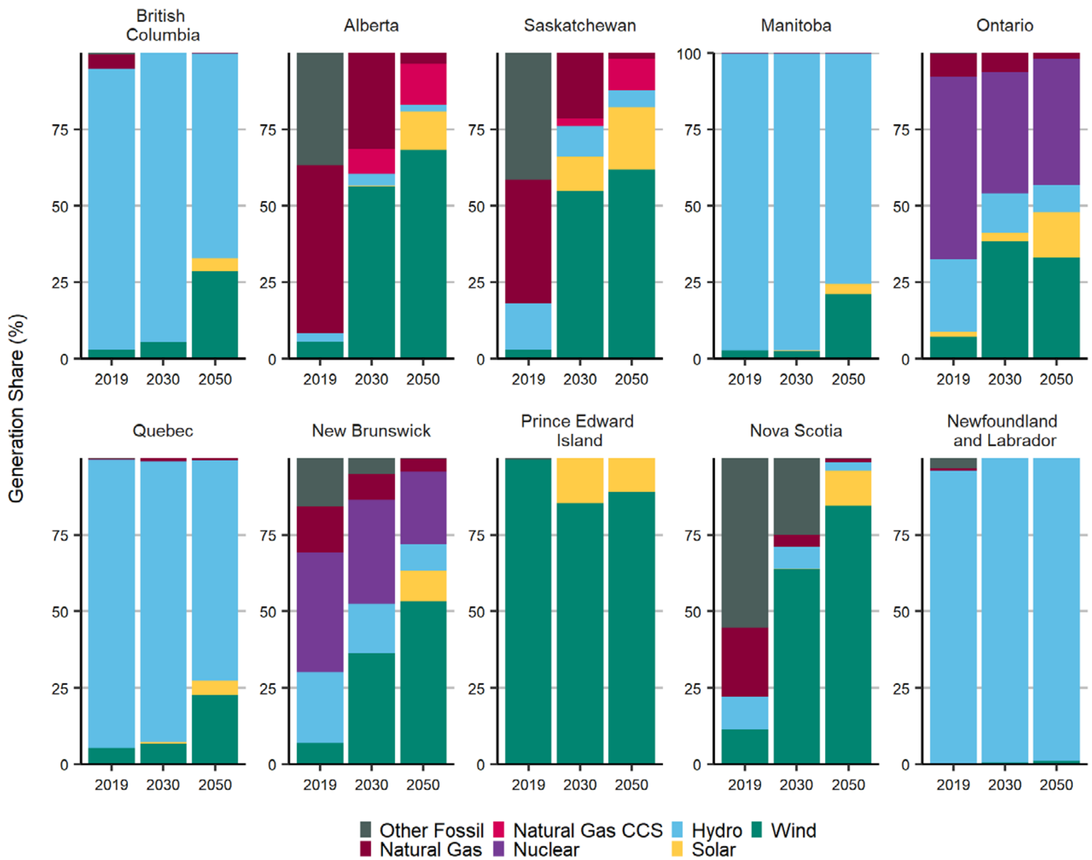
Natural gas-fired electricity generation remains a relatively important share, about 15%, of the electricity supply of Alberta and Saskatchewan in the main net-zero electricity scenario. However, by 2050, the vast majority of this generation utilizes CCS technology. In many other provinces, although the generation share is small, natural gas units nonetheless provide flexible capacity required to maintain system reliability.

Transmission between provinces is a key factor that enables the electricity system to reach net-zero. For example, in the Base net-zero electricity scenario, increased transmission occurs in western Canada, where hydroelectric generation from B.C. and Manitoba helps Alberta and Saskatchewan decarbonize.

While we continue to see diversity between the various provincial electricity systems in each net-zero electricity scenario, results vary somewhat between cases. In a scenario where transmission expansions are limited, Alberta and Saskatchewan use more generation from natural gas with CCS. By contrast, in the Higher Carbon Price scenario, natural gas with CCS is lower in these provinces as small modular reactors make inroads in western Canada. Meanwhile, in the Hydrogen scenario there is a 26% reduction of all types of natural gas-fired generation relative to the main net-zero electricity scenario in 2050, and the flexible nature of hydrogen-fired generation means battery storage falls by 32%. In the Bioenergy with CCS (BECCS) scenario, the availability of biomass CCS units for electricity generation partially displaces all other generation technologies in Alberta and Saskatchewan. Due to the carbon removal capability of biomass CCS, the electricity system in Canada becomes a net negative emissions economic sector in the BECCS scenario.

Figure ES.7:

Electricity Generation Share by Technology, Main Net-Zero Electricity Scenario



5. In the Evolving Policies Scenario, crude oil production grows much more slowly than in the past decade, rising 16% to a peak of 5.8 MMb/d in 2032. Afterwards, production declines slowly to 2050. As crude oil available for export from western Canada increases over the next decade , it comes close to filling the level of total export capacity that would be provided by existing pipeline capacity, planned pipeline expansions, and structural rail.

Canadian crude oil production recovered to pre-pandemic levels by late 2020, after steep reductions in the spring of 2020. In both scenarios, production increases in the near term, but long-term trends differ significantly based on scenario assumptions, such as future price levels and domestic climate policy.

In the Evolving Policies Scenario, Canadian production growth slows over the next decade, peaking at 5.8 million barrels per day (MMb/d) in 2032, up from 5.0 MMb/d in 2021 (Figure ES.8). After 2032, production declines steadily, reaching 4.8 MMb/d in 2050. In the Evolving Policies Scenario, the assumed Brent crude oil price gradually falls from an annual average of US$68 per barrel in 2021 to US$40 per barrel in 2050 (2020 dollars, adjusted for inflation).

Canadian crude oil production levels are resilient through to 2050 despite the Evolving Policies Scenario's relatively low prices and steadily more ambitious climate policies. This largely stems from the nature of the oil sands facilities, which are long-lived and have low operating costs once built. Throughout the projection period, the vast majority of oil sands production is from facilities that are producing today (Figure ES.9).

Future global climate policy, and how it affects global crude oil markets, will be important for Canadian production. The Current Policies Scenario assumes higher global oil prices than the Evolving Policies Scenario, premised on there being higher global oil demand. The Brent crude oil price stays at US$70 per barrel through much of the projection period and Canadian production increases more rapidly, plateauing in 2040 at 6.7 MMb/d. Conversely, some recent global net-zero scenarios, such as the International Energy Agency's Net Zero Emissions by 2050 scenario in World Energy Outlook 2021, show rapidly declining global oil demand, which could lead to significantly lower Canadian production levels compared to the Evolving Policies Scenario.

Figure ES.8:
Crude Oil Production, Evolving and Current Policies Scenarios

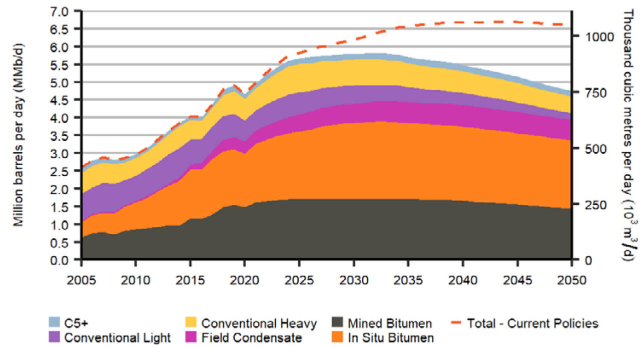
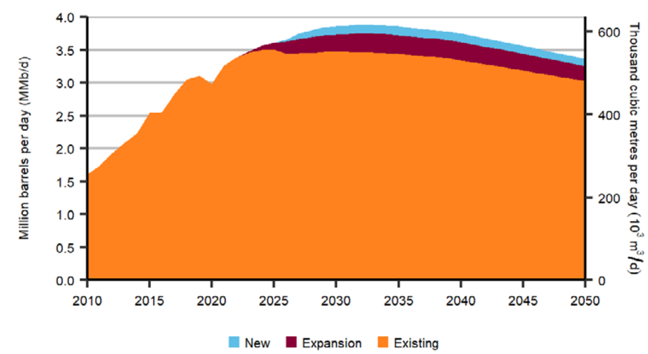


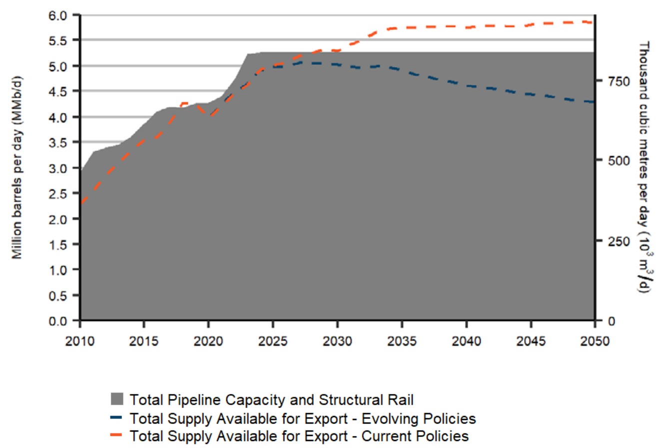
Figure ES.9:
Oil sands Production from Currently Producing Facilities, Expanded, and New Facilities, Evolving Policies Scenario



A key issue for Canadian oil pricing and production trends over the last number of years was the availability of crude oil export pipeline and rail capacity. In the Evolving Policies Scenario, crude oil available for export from western Canada comes very close to, but stays slightly below the illustrative total export capacity provided by existing plus planned pipeline capacity and structural rail, as shown in Figure ES.10. EF2021 does not assess whether additional pipeline capacity would be required to avoid constraining Canadian crude oil production below levels projected in the Evolving Policies Scenario. In the Current Policies Scenario, however, production would clearly be constrained below projected levels without additional pipeline capacity, as supply significantly exceeds the illustrative total export capacity through much of the projection period. Our crude oil supply projections are not adjusted to reflect potential pipeline constraints in either scenario.

Figure ES.10:

Illustrative Export Capacity from Pipelines and Structural Rail, vs. Total Crude Oil Supply Available from the Western Canadian Sedimentary Basin (WCSB), Evolving and Current Policies Scenarios



Crude Oil Pipelines in Canada's Energy Future

The *Canada's Energy Future* series makes projections of energy production and use in Canada. To develop these projections, we need to make assumptions about crude oil markets. Figure ES.10 is an illustrative comparison of our crude oil supply projections with the level of total export capacity that would be provided if planned pipeline expansions go ahead, existing pipelines otherwise experience no increases or decreases in capacity, and a consistent level of structural rail exports continues.

Making this comparison provides insight into whether pipeline constraints might impact crude oil production in our scenarios. However, we do not adjust our crude oil production projections based on potential constraints. EF2021 does not explore the complexities of how pipeline infrastructure interacts with energy supply and demand outcomes. Instead, EF2021 assumes that western Canadian crude oil prices will consistently track prices in international markets. In reality, this is not always the case. For example, if the pipeline system is very full–where export volumes are above or only slightly below total pipeline capacity–crude prices in western Canada can fall well below prices in international markets.

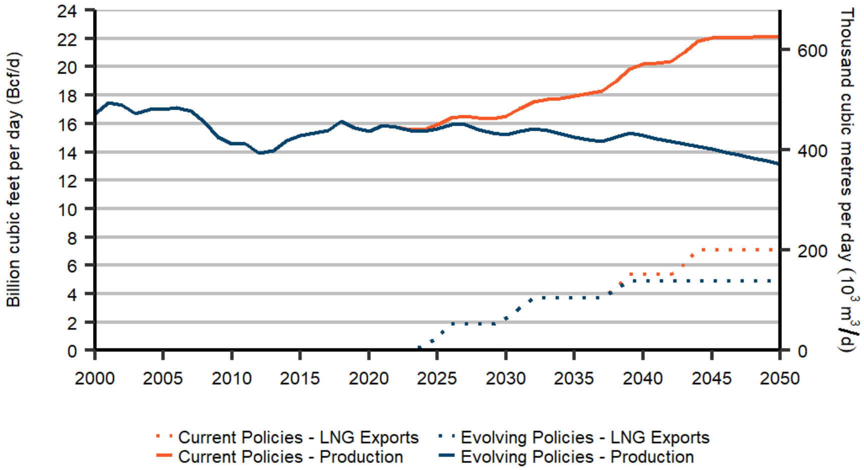
Sufficient spare pipeline capacity is generally required for western Canadian prices to consistently track prices in international markets. Spare capacity provides oil producers and others in the marketplace with flexibility to access higher value markets, and avoid the impacts of maintenance, unforeseen outages, and higher cost rail. This flexibility would remain even with excess capacity and long-term underutilization of pipelines, though this could result in higher pipeline tolls, which could lead to some consistent incremental discounting of western Canadian crude prices. Analysis of these considerations is beyond the scope of EF2021. We caution readers from drawing definitive conclusions from the illustrative comparison shown Figure ES.10.

6. Investment in natural gas production is spurred by assumed liquefied natural gas (LNG) exports in both scenarios. In the Evolving Policies Scenario, nearly 40% of Canadian natural gas production is liquefied and exported to global markets by 2050. Despite considerable LNG-related production growth, natural gas production remains relatively stable through much of the projection period before declining gradually to reach 13.1 Bcf/d by 2050, 17% lower than current levels.

In the Evolving Policies Scenario, natural gas production remains near current levels of approximately 15.5 billion cubic feet per day (Bcf/d) through much of the next two decades. We assume that LNG exports grow over that period, starting with 1.8 Bcf/d by 2026 and reaching 4.9 Bcf/d by 2039 in the Evolving Policies Scenario. The additional investment in production to feed these LNG exports sustains overall production levels. Without LNG, production would otherwise decline given the assumed natural gas prices and the costs associated with assumed domestic climate policies. After 2040, with LNG exports assumed to stay flat, total production begins to decline, falling to 13.1 Bcf/d by 2050. Assumed Henry Hub natural gas prices in the Evolving Policies Scenario steadily increase from US$3.00 per Million British Thermal Units (MMBtu) in 2021 to US$3.64/MMBtu by 2050 (2020 dollars, adjusted for inflation).

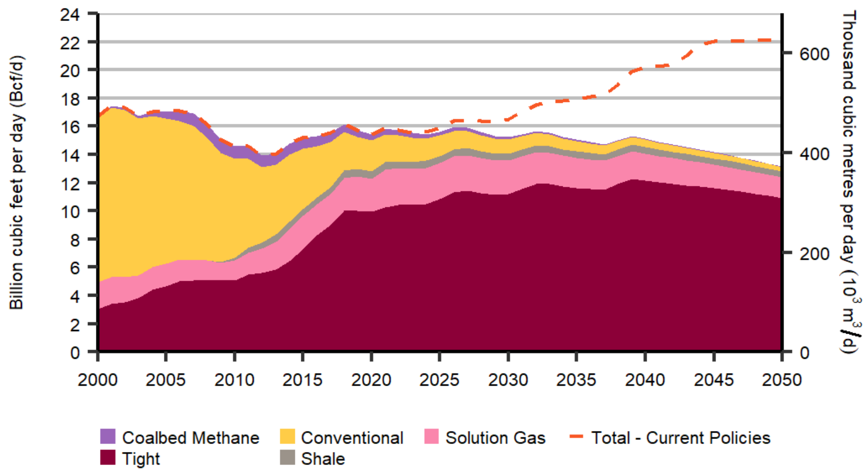
In the Current Policies Scenario, natural gas production is significantly higher. To reflect higher global and North American demand for natural gas due to the scenario's lower climate action, we assume LNG exports increase to 7.1 Bcf/d by 2044 and the Henry Hub price reaches $4.40/MMBtu by 2050 (2020 dollars, adjusted for inflation). These two drivers, combined with less stringent domestic climate policies relative to the Evolving Policies Scenario, lead to natural gas production increasing steadily throughout the projection, reaching 22.2 Bcf/d in 2050, a 40% increase from 2021 production levels.

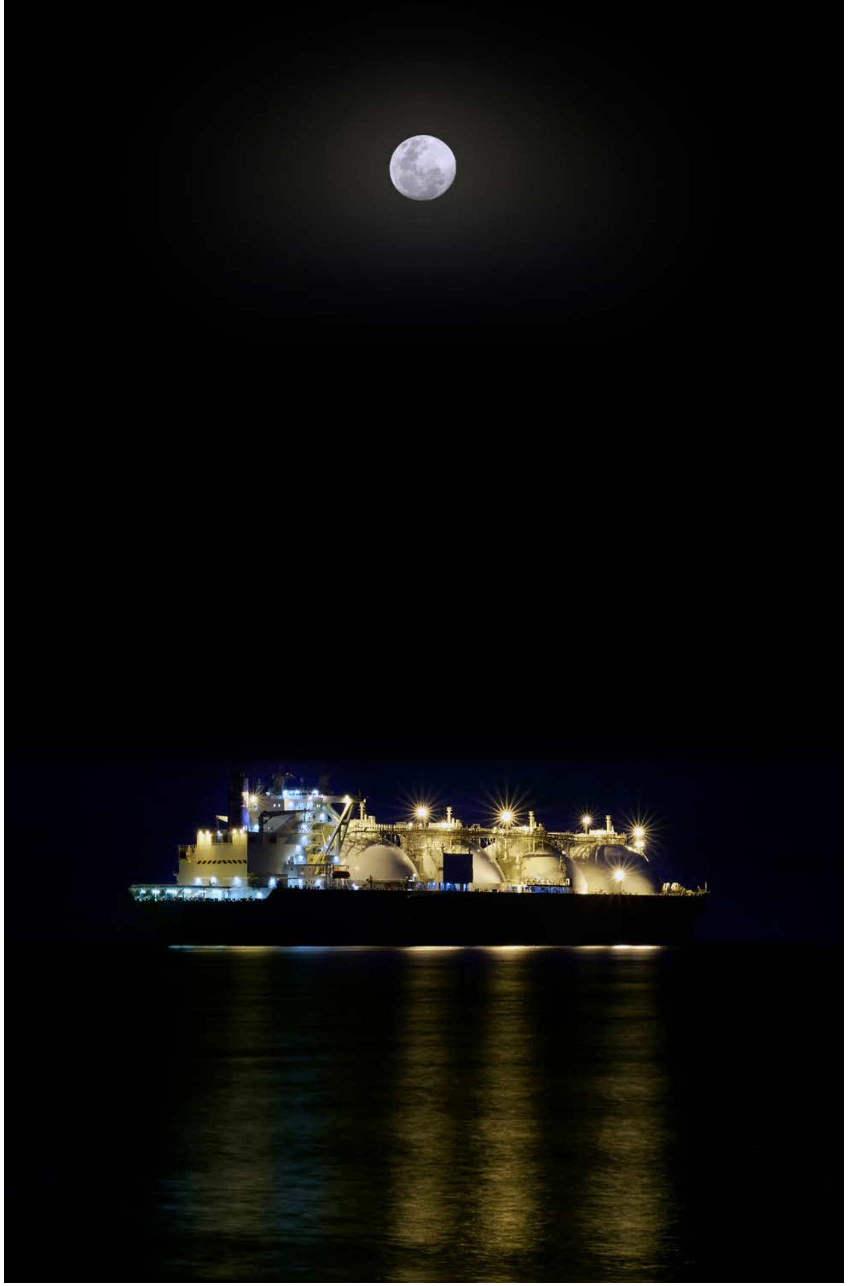
Figure ES.11:
Total Natural Gas Production and LNG Export Assumptions, Evolving and Current Policies Scenarios

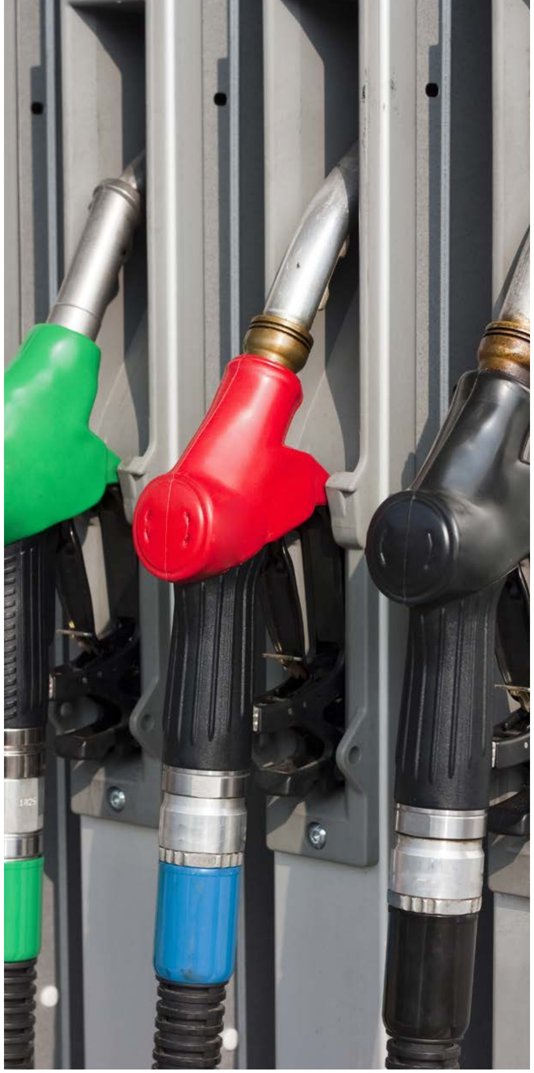


In both scenarios, natural gas production from the Montney Formation, which straddles the Alberta-B.C. boundary and is rich in higher value natural gas liquids (NGLs), grows significantly. In many other regions, production is stable or declines throughout the projection. Much of the production growth related to LNG exports occurs in B.C. and production in B.C. surpasses that of Alberta by 2028.

Figure ES.12:
Natural Gas Production, Evolving and Current Policies Scenarios







7. As Canada's energy system decarbonizes in the Evolving Policies Scenario, we use less fossil fuels. Coal becomes a negligible part of the energy mix. Use of oil-derived fuels declines, especially gasoline and diesel for transportation. After briefly rising in the near term, total natural gas use declines, and our consumption of natural gas is increasingly tied to the future of CCS. Natural gas with CCS for industrial uses, power generation, and hydrogen production are key demand growth areas.

In the Evolving Policies Scenario, total Canadian fossil fuel use declines over 40% from 2021 to 2050. However, projections differ across the various fossil fuels. Canadian demand for natural gas has seen relatively strong growth over the last decade, driven by increased use in the oil sands and power generation as coal was phased out. In the Evolving Policies Scenario, gas demand grows over the next two years, as Alberta electricity producers aim to no longer use coal for electricity generation by 2023. Over the longer term, although natural gas remains an important part of Canada's energy mix, total demand declines from around 13 Bcf/d in 2021 to 8.5 Bcf/d in 2050. Factors that reduce natural gas demand include: increasing use of renewables in power generation, renewable natural gas and hydrogen blended into gas streams, energy efficiency improvements, and declining crude oil and natural gas production (which itself requires natural gas). These declines are partially offset by applying CCS technology when using natural gas in industry, the power sector and to produce low-carbon hydrogen.

Coal consumption declines significantly over the projection, driven by its phase-out from electricity generation. Coal drops to less than 1% of Canada's energy mix by 2035, compared to 5% in 2019. Use of refined petroleum products (RPPs) and NGLs gradually falls throughout most of the projection period, driven by declines in gasoline and diesel fuel demand. In the earlier years, this fall is driven by fuel efficiency improvements and increased blending of biofuels, and in the long term by increased use of electric and hydrogen vehicles in transportation. Demand for RPPs used for non-combustion purposes (petrochemical feedstocks, asphalt, lubricants, etc.), as well as for aviation fuel, is relatively steady throughout the projection.

Figure ES.13:
Fossil Fuel Demand by Type, Evolving Policies Scenario

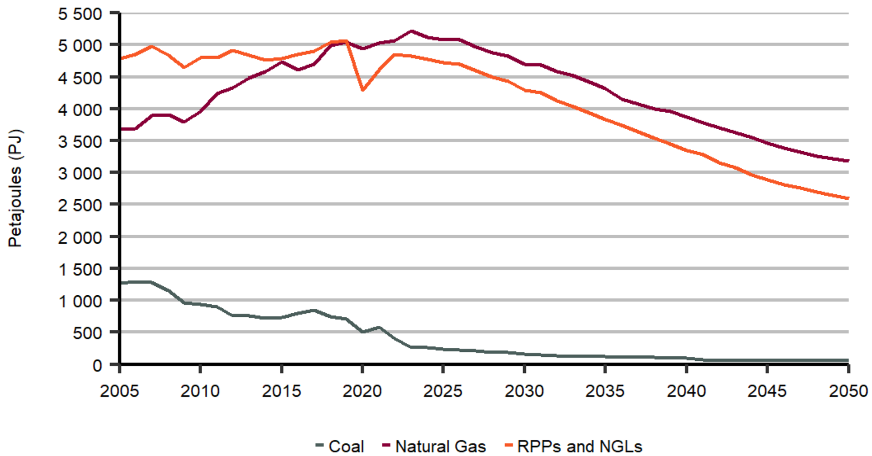
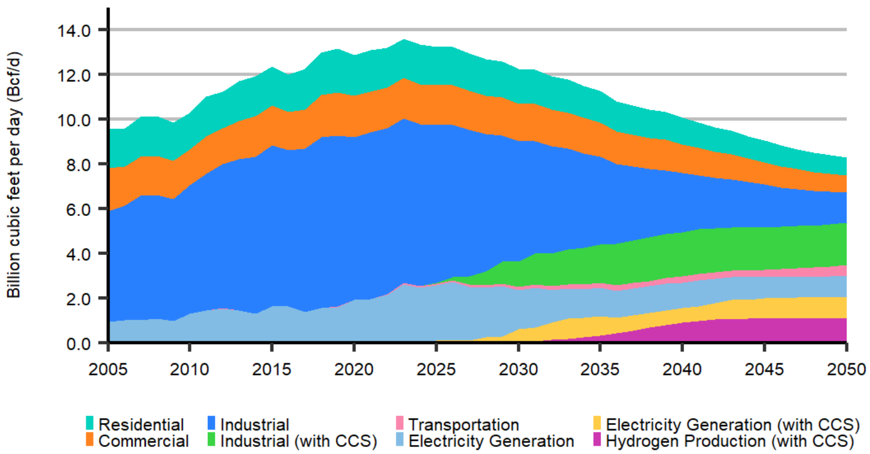


Figure ES.14:
Natural Gas Demand by Sector, Evolving Policies Scenario



Scenarios and Assumptions

This chapter describes the two core scenarios in EF2021, the Evolving Policies Scenario and the Current Policies Scenario, and the assumptions that underpin those scenarios. The six scenarios, and underpinning assumptions, that explore what achieving net-zero means for Canada's electricity system are described in the "Towards Net-Zero" section of this report. However, Figure A.1 illustrates the key differences between the two core scenarios and the group of six additional net-zero scenarios that explore the electricity system.

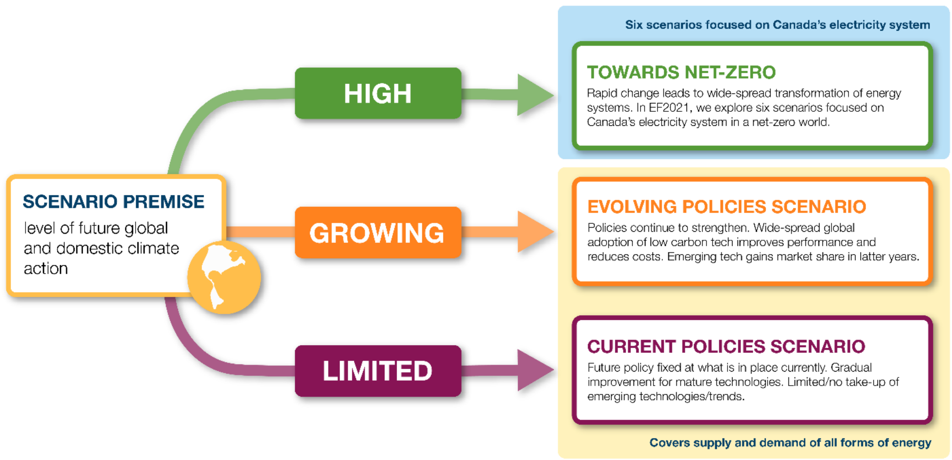
Scenario Premise

EF2021 includes two core scenarios: the Evolving Policies Scenario and the Current Policies Scenario. The central premise to these scenarios is based on the level of future climate action, both globally and domestically. The Evolving and Current Policies scenarios provide projections for all energy commodities and all Canadian provinces and territories.

The primary scenario in EF2021 is the Evolving Policies Scenario. The core premise of the scenario is that action to reduce the GHG intensity of our energy system continues to increase at a pace similar to recent history, in both Canada and the world. Relative to a scenario with less action to reduce GHG emissions, this evolution implies less global demand for fossil fuels, and greater adoption of low-carbon technologies. In contrast, the core premise of the Current Policies Scenario is that there is generally no additional action to reduce GHGs beyond those policies in place today, implying relatively higher global demand for fossil fuels and less adoption of low-carbon technologies. Consistent with these implications, the Evolving Policies Scenario assumes lower international prices for fossil fuels and a higher pace of technological change over the projection period, compared to the Current Policies Scenario.

The Evolving and Current Policies scenarios do not explicitly model climate goals or targets. Given its static policy framework, the Current Policies Scenario is extremely unlikely to lead to the significant GHG reductions needed to meet Canada's Paris commitments. In the Evolving Policies Scenario, significant GHG emission reductions will be realized, but ambitious goals such as net-zero by 2050 are unlikely to be met.

Figure A.1:
Conceptual Illustration of EF2021 Scenarios



The Energy Futures Analytical Process

The analysis in EF2021 follows a three-step process

1. Define the premises of the Scenarios: We develop the scenarios in the *Canada's Energy Future* series to explore key uncertainties for the future of the energy system. In EF2021, the primary premise which differentiates the scenarios is the level of global and domestic climate action. We then consider the implications of that premise on factors such as global fossil fuel demand and technology development. These implications are discussed further in this section, under the heading "Scenario Premise."

2. Make explicit assumptions on key inputs: We then make explicit assumptions about key factors which will influence the Canadian energy system. These assumptions are intended to be consistent with the scenario premises defined in Step 1. Key inputs include specific domestic climate policies such as carbon prices, international crude oil and natural gas benchmark prices, and technology cost and performance trends. These are detailed in this section under the heading "Key Assumptions."

3. Develop projections: Given these input assumptions, we develop projections to 2050 using the Energy Futures Modeling System. Results from these projections are included in the following chapters. Additional information about the energy modeling system is included in Appendix 2: Overview of the Energy Futures Modeling System.

Table A.1:
Explaining the Scenarios and Relationship Between the Assumptions

KEY DIFFERENCES BETWEEN SCENARIOS	EVOLVING POLICIES	CURRENT POLICIES
SCENARIO PREMISE	**PREMISE**: Continually increasing global and Canadian action to reduce GHG emissions. The pace of increase in future action continues the historical trend.	**PREMISE**: Global and Canadian action to reduce GHG emissions generally stops at current levels.
INTERNATIONAL CRUDE OIL MARKETS	**GENERAL IMPLICATION**: Due to increasing policy action, global crude oil demand is lower than the Current Policies Scenario.	**GENERAL IMPLICATION**: Less policy action leads to higher global crude oil demand compared to the Evolving Policies Scenario.
	EXPLICIT ASSUMPTION INCLUDED IN EF MODELING: Lower demand implies lower crude oil prices compared to the Current Policies Scenario. Brent crude oil trends gradually downward, reaching $40/bbl 2020USD in 2050.	**EXPLICIT ASSUMPTION INCLUDED IN EF MODELING**: Stronger demand implies stronger crude oil prices compared to the Evolving Policies Scenario. Brent crude oil averages $70/bbl 2020USD through most of the projection period.
INTERNATIONAL NATURAL GAS MARKETS	**GENERAL IMPLICATION**: Due to increasing policy action, global natural gas demand is lower than the Current Policies Scenario.	**GENERAL IMPLICATION**: Less policy action leads to higher global natural gas demand compared to the Evolving Policies Scenario.
	EXPLICIT ASSUMPTION INCLUDED IN EF MODELING: Henry Hub natural gas prices rise from $3.00/MMbtu 2020 USD in 2021, but at a slower pace than the Current Policies Scenario, reaching $3.64/mmbtu 2020USD in 2050. Canadian liquefied natural gas (LNG) exports increase to 4.9 bcf/d by 2050.	**EXPLICIT ASSUMPTION INCLUDED IN EF MODELING**: Henry Hub natural gas prices rise faster and higher than in the Evolving Policies Scenario, to $4.40/mmbtu 2020USD in 2050. Canadian LNG exports increase to 7.1 bcf/d by 2050.
LOW-CARBON TECHNOLOGIES	**GENERAL IMPLICATION**: Increasing policy action drives increasing global adoption of low-carbon technologies, which leads to cost and efficiency improvements as technology advances.	**GENERAL IMPLICATION**: Limited policy action provides a weaker incentive for global technology adoption. Cost declines and performance of low-carbon technologies are weaker compared to the Evolving Policies Scenario
	EXPLICIT ASSUMPTION INCLUDED IN EF MODELING: Costs for technologies with a growing market share, such as wind and solar power, fall faster compared to the Current Policies Scenario. Emerging technologies are included on a larger scale. Performance of both technology categories improves as compared to the Current Policies Scenario.	**EXPLICIT ASSUMPTION INCLUDED IN EF MODELING**: Costs continue to improve for technologies where there is a clear trend, such as wind and solar power, but at a slower rate than the Evolving Policies Scenario. Limited inclusion of emerging technologies.
DOMESTIC CLIMATE POLICIES	**GENERAL IMPLICATION**: Policy action continues to increase at the pace of the historical trend.	**GENERAL IMPLICATION**: Policy action is fixed to what is currently in place.
	EXPLICIT ASSUMPTION INCLUDED IN EF MODELING: A hypothetical suite of future policy changes is assumed. This includes an increase in carbon pricing beyond 2030, tightening of standards for large emitters, a national ZEV mandate, and an increasingly strict emissions intensity mandate for fuels beyond 2030.	**EXPLICIT ASSUMPTION INCLUDED IN EF MODELING**: Only policies that are law or near-law are included.

Table A.1 summarizes the implications of the core premise of the scenarios across some key areas. It describes how the premise of the Evolving and Current Policies scenarios affects each area, first in a general sense (rows labelled “General Implication”) and then how these translate into explicit assumptions, such as prices or technology costs, included in the EF models (rows labelled “Explicit Assumption Included in EF Modeling”). Many of these areas, such as international markets and technology development, are international in nature. Since EF2021 analysis is focused on Canada, the explicit assumptions, such as market prices and technology cost trends, are developed via a review of global scenario analysis produced by institutions, academia, industry, private forecasters, and other relevant energy analysis.[3]

[3] Key resources that informed the Evolving and Current Policies scenario assumptions include: ECCC Healthy Economy, Healthy Environment (2021), various federal, provincial and territory policy documents, IEA World Energy Outlook (2020) and Net-Zero by 2050 (2021), EIA Annual Energy Outlook (2021) and Short Term Energy Outlook (various 2021), BP Outlook (2020), Shell Scenarios (2021), National Renewable Energy Laboratory Annual Technology Baseline (2021), price forecasts from GLJ and Sproule, and scenario analytics services from IHSMarkit, S&P Global, and WoodMackenzie.

EF2021 is a Baseline for Discussion

It is important to note that the projections presented in EF2021 are a baseline for discussing Canada’s energy future today and do not represent the CER’s predictions of what will take place in the future. EF2021 projections are based on assumptions which allow for analysis of possible outcomes. Any assumptions made about current or future energy infrastructure, market developments, or climate policies, are hypothetical and have no bearing on any regulatory proceeding that is, or will be, before the CER.

Over the projection period, it is likely that developments beyond normal expectations, such as geopolitical events or technological breakthroughs, will occur. Also, new information will become available, and trends, policies, and technologies will continue to evolve. This report is not an official, or definitive, impact analysis of any specific policy initiative, nor does it aim to show how specific goals, such as Canada’s climate targets, will be achieved.

Key Assumptions

Domestic Climate Policy

The Evolving Policies Scenario begins with domestic climate policies currently in place. It then builds on the current policy framework with a hypothetical suite of future policy developments. These policies are chosen to reflect increasing ambition to reduce GHG emissions, and generally align with the broad trends of historical progress. Alternatively, the Current Policies Scenario only includes policies that are currently in place. This section outlines specific policies included, and additional policy detail is available in Appendix 1: Domestic Climate Policy Assumptions.

Existing policies:

The Current Policies Scenario includes only policies that currently exist. In the Evolving Policies Scenario, existing policies provide a baseline that is built upon over the projection.

In order to determine whether to include a policy in the analysis, the following criteria were applied:

- The policy was publicly announced prior to 1 August 2021.
- Sufficient details exist to model the policy.[4]
- Goals and targets, including Canada's international climate targets, are not explicitly modelled. Rather, policies that are announced, and in place, to address those targets are included in the modelling and analysis.

Relative to Canada's Energy Future 2020 (EF2020), key changes in the Evolving and Current Policies scenarios include the increased carbon pricing included in the Federal Strengthened Climate Plan. The Clean Fuel Standard for liquid fuels has also been included in the Current Policies Scenario, following the publishing of the draft regulations in December 2020.

[4] For example, in July 2021, the Federal government announced a forthcoming mandate for all passenger vehicle sales to be zero-emissions by 2035, but at the time of analysis there was not sufficient detail to include this mandate in the Current Policies Scenario.

Future policies:

The Evolving Policies Scenario adds a hypothetical suite of future policy developments to existing policies. These policy assumptions take into account several considerations:

- Announced policies that are currently in the development stage are included to the extent possible. Generally, their inclusion requires simplifying assumptions as final regulations are not available.
- Some policies that are being increasingly enacted by various jurisdictions are broadened to other jurisdictions later in the projection period.
- Existing policies that can be strengthened over time, are strengthened. For example, following the carbon price increases to 2030 that are set out in current policy, we include a hypothetical carbon price that continues to rise from 2031 to 2050, as well as a hypothetical tightening of the benchmarks for large emitters subject to the output-based pricing system.

Table A.2 describes specific policy initiatives. Figure A.2 compares the federal backstop carbon price to the increasing cost of carbon pollution in the Evolving Policies Scenario.

Table A.2:
Overview of Domestic Policy Assumptions

Key Differences Between Scenarios

Key Existing Policy Assumptions:
The base for policy assumptions in the Evolving Policies Scenario, while the Current Policies Scenario only includes these existing policies.

Policy	Description
Carbon Pricing	Current provincial and territorial systems, as well as the Federal Carbon Pricing Backstop.
Coal Phase-Out	Traditional coal-fired generation is phased out of electricity generation by 2030.
Clean Fuel Regulation	Liquid fuels only, where standard strengthens to 2030.
Energy Efficiency	Currently in place regulations including appliance standards, building codes, and vehicle standards.
Electric Vehicles	Provincial policies and initiatives including those in British Columbia (B.C.) and Quebec, as well as Federal rebates and infrastructure program.[5]
Renewable Energy	Current requirements for renewable electricity, and blending of ethanol, biodiesel, and renewable natural gas.

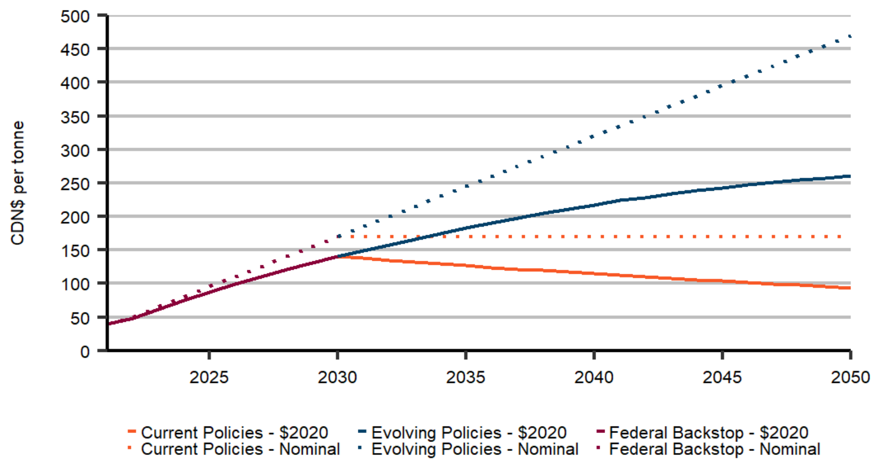
Key Future Policy Assumptions:
Hypothetical increases in policy stringency only included in the Evolving Policies Scenario

Hypothetical Policy Change	Description
Carbon pricing	Carbon prices continue to rise beyond existing announcements. For the federal pricing system, prices continue to increase after 2030 at $15 per tonne of carbon dioxide equivalent (CO_2e) per year, in nominal terms, as shown in Figure A.2. In systems for large emitters, such as the federal output-based pricing system, benchmarks are tightened by 2% annually from 2022 to 2050.
Low Carbon/Clean Fuel Regulations	The Federal Clean Fuel Regulation emission intensity improvement trend (2022-2030) for liquid fuels is extrapolated through the remainder of the projection period. A federal renewable natural gas blending requirement is introduced in 2030, rising to 10% by 2040.
Zero-Emission Vehicles	A federal zero-emission vehicle (ZEV) mandate is introduced in 2025, rising to 100% of new passenger vehicle sales by 2035 in the provinces. Remote communities and the territories are assumed to be exempt.
Energy Efficiency	Gradually stronger energy efficiency regulations across the economy, including net-zero-ready building codes, improving appliance standards, and increasing light-duty vehicle efficiency standards.
Support for clean energy technology and infrastructure	Policy continues to support new technology development as well as key infrastructure developments including electric transmission, carbon capture and storage (CCS), hydrogen production, and electric vehicle charging infrastructure.

[5] In June 2020 the Federal government announced a goal for 100% of car and passenger truck sales to be zero-emission by 2035 in Canada.
At the time of analysis, policy measures to achieve this target were still under development, and this goal is not included in the Current Policies Scenario.

Figure A.2:

Current Federal Backstop Carbon Pricing Schedule[6] (2020 to 2030), and Evolving and Current Policy Scenario Economy-wide Carbon Pricing Assumptions (2030 to 2050)



---

[6] For illustration purposes: In the EF2021 analysis, carbon prices are modeled based on individual provincial and territorial systems, many of which differ from the federal backstop system. The Federal Backstop price includes the announced increase to $170/tonne by 2030 in nominal terms. For the remainder of the Current Policies Scenario projection, this is held constant, and the price in inflation-adjusted terms declines by the rate of inflation.

Evolving Policies Scenario: Key Changes between EF2020 and EF2021

The Evolving Policies Scenario was introduced as the new primary scenario of the *Canada's Energy Future* series in EF2020. In the time since EF2020 analysis was completed, there have been some significant changes in global and domestic trends that have led to revisions in Evolving Policies Scenario assumptions between EF2020 and EF2021. Key changes include:

- **Significantly stronger domestic climate policy, including Canada's Strengthened Climate Plan carbon price path.** Several new domestic policy initiatives have been introduced, including a higher federal carbon pricing backstop to 2030, draft regulations for the federal clean fuel regulation, and several provincial and territorial policies and plans.

- **Higher crude oil and natural gas prices in the near term, but lower prices in the longer term.** Prices have trended higher than those in EF2020 in the near term, through the combined effect of pandemic recovery, vaccine rollout, and global crude oil production cuts. Over the longer term, EF2021 crude oil and natural gas prices are lower than EF2020, in light of several new international policy and GHG reduction target announcements.

- **Increased momentum for emerging technologies.** Since EF2020's release, Canada has released hydrogen and small modular reactor (SMR) roadmaps. Automakers have announced more models of electric vehicles (EVs). Several major carbon-capture and storage (CCS) and hydrogen projects have also been announced.[7]

---

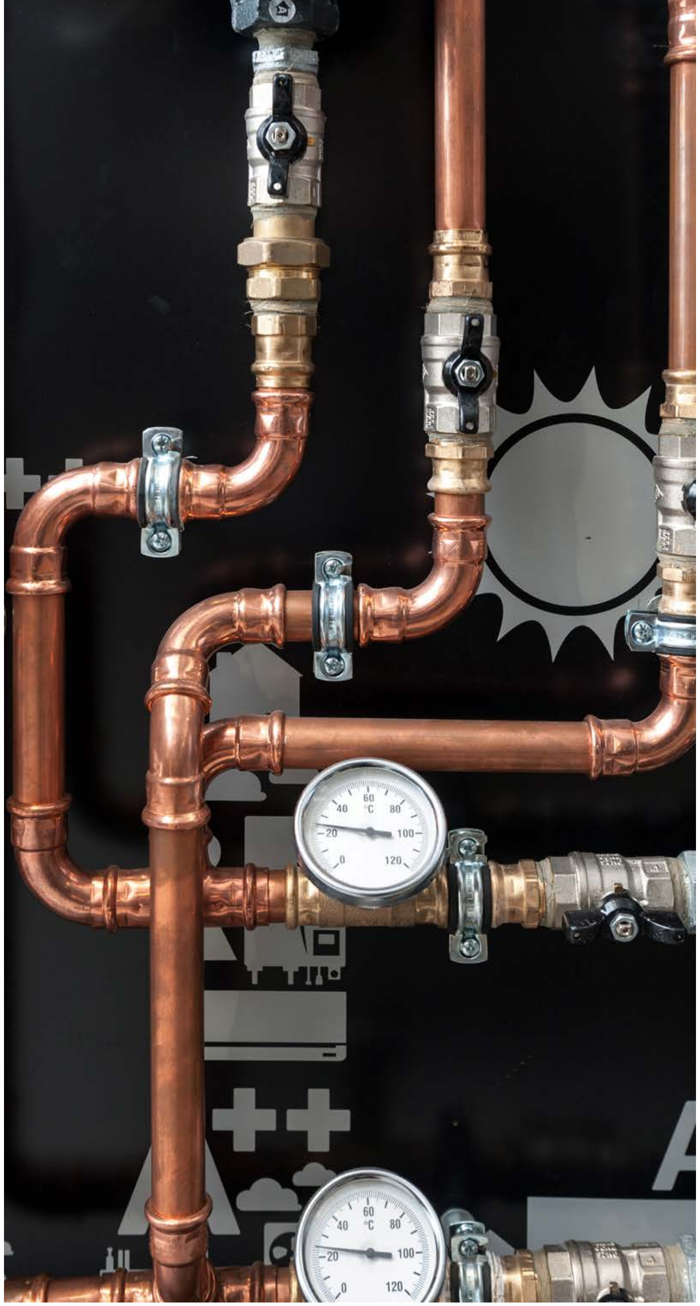
[7] These include the Hydro-Québec green hydrogen electrolyzer project, the Air Products Net-Zero Hydrogen Energy Complex, the Pembina and TC Energy Alberta Carbon Grid, Pieridae Caroline Carbon Capture Power Complex, Nauticol Energy and Enhance Energy's Blue Methanol facility, and the Shell Polaris CCS project.

Technology

Technological changes can have large impacts on energy systems. There is a strong link between policies and the pace of technological development. Policy frameworks are key drivers of technological innovation and greater use of GHG-reducing technologies. Over the past decade, technological advancements have provided access to unconventional fossil fuel resources and dramatically reduced the cost of technologies like wind, solar, and batteries. The Evolving Policies Scenario assumes substantial technological progress, including adoption of many promising technologies currently in the early stages of commercialization. The Current Policies Scenario assumes slower technological progress compared to the Evolving Policies Scenario, including incremental efficiency improvements and cost reductions for well-established technologies. Table A.3 provides an overview for key technology assumptions in the Evolving and Current Policies Scenarios.

Table A.3:
Technology Assumptions, Evolving and Current Policies Scenarios

Technology	Evolving Policies Scenario	Current Policies Scenario
Wind and Solar Electricity	Costs fall and performance improves. See table A.4 for details.	Costs continue to fall, but at a slower rate than the Evolving Policies Scenario. See table A.4 for details.
Electric Vehicles	Battery costs fall from 2020US$ 170/kilowatt (kW) in 2021 to $ 45/kW in 2050 (reduction of 74%).	Battery costs fall to 2020US$ 100/kW by 2050 (reduction of 40%).
Hydrogen	Cost of low-carbon hydrogen falls throughout the projection period. Electrolysis hydrogen falls from $2020 US$ 6-10 currently to $1.5-6 by 2050. Natural gas with CCS derived hydrogen falls from $2020 US$ 1.6-2 currently to $1.5-1.7 by 2050.	Currently announced projects included, costs remain near current levels.
Renewable Natural Gas	Costs an average 2020US$ 15/GJ throughout the projection, with a maximum demand of 500 petajoules (PJ).	Only current projects and in-place blending policies (B.C. and Quebec) are included.
Solvent-Assisted Oil Sands Extraction	All new oil sands facilities added post 2025 include solvent-assisted extraction. Adoption in existing facilities begins in the latter half of the projection period.	Limited adoption of solvent-assisted technology.
Small Modular Nuclear Reactors (SMRs)	Cost falls from 2020US$ 7000/kW in 2030 to 6000/kW in 2040, 5000/kW in 2050.	Not included.



Critical Minerals and the Energy Transition

A continued global transition toward low-emission energy systems will involve the deployment of many existing and emerging technologies, such as wind turbines, solar panels, and batteries. These technologies require input materials, and global scenario analysis (such as International Energy Agency's (IEA's) *Net Zero by 2050* and *The Role of Critical Minerals in Clean Energy Transitions*, and MIT Energy Initiative's *Insights into Future Mobility*) are increasingly focused on the inputs necessary to produce these technologies. The cost and availability of minerals that are needed to manufacture low-carbon technologies are key uncertainties for energy systems.

Increasing demand for these critical minerals (such as lithium, cobalt, nickel, and copper) could put upward pressure on their prices. In turn, increasing raw material prices could limit cost reductions for wind, solar, and batteries. If costs of these technologies are higher than assumed in the EF2021 scenarios (see Table A.4), there could be lower adoption than projected, and/or higher energy system costs.

Conversely, sustained demand for critical minerals can encourage investment in new sources of supply or increased recycling, potentially keeping price increases at bay or even driving down prices over time.[8] Technology development could offset potential increases in input material costs through changes in design (such as changing lithium-ion battery chemistry to use less cobalt, and/or use of different technologies, such as moving towards a solid-state battery and away from the nickel-manganese-cobalt technology used today), or production improvement.[9]

Although the outlook for the global critical minerals market is uncertain, it is clear that mining critical minerals for low-carbon technologies will have major economic impacts. The IEA's Net Zero Energy scenario estimates that the global value of select critical minerals will grow substantially over the next two decades, reaching today's level for coal market value (about $400 billion 2019USD) by 2040. In the Canadian context, the Canadian Institute for Climate Choices' *Canada's Net Zero Future* study finds that increased mining and manufacturing activity could be an important contributor to Canada's economic growth as Canada and the world decarbonize.

[8] For example, exploration for rare earth metals substantially increased in the early 2010s, driven by the prospect of increased demand (Eggert, R. G. (2011). Minerals go critical. Nature Chemistry, 3, 688-691.). For a discussion of critical minerals exploration dynamics see Humphreys, D. (2014). The mining industry and the supply of critical minerals. In British Geological Survey, Critical Metals Handbook (pp. 20-40). John Wiley & Sons, Ltd. doi:10.1002/9781118755341.

[9] See Victoria et al., Solar photovoltaics is ready to power a sustainable future, Joule (2021), for a discussion on how production efficiencies have reduced material needs for Solar PV, and reduced risk exposure to input materials.

Crude Oil and Natural Gas Markets

International crude oil and natural gas prices are a key driver of the Canadian energy system and are determined by supply and demand factors beyond Canada's borders. Canadian crude oil and natural gas benchmark prices (such as western Canada Select (WCS) for heavy crude oil and Nova Inventory Transfer (NIT) for natural gas) are driven by international trends, but are also driven by local factors, such as local crude quality and adequacy of pipeline capacity. In recent years, the availability of pipeline capacity within and leaving western Canada has been a key issue that has affected both Canadian markets and production levels.

Figure A.3 shows the EF2021 crude oil assumptions for Brent, the primary global benchmark price for crude oil, for the Evolving and Current Policies scenarios. Global crude oil prices fell in 2020 due to the COVID-19 pandemic. In the second half of 2021, prices have increased to 2019 levels and above. In the longer term, prices in the Evolving and Current Policies scenarios diverge based on their different premises. In the Evolving Policies Scenario increased global action on climate change, which implies reduced demand for crude oil relative to the Current Policies Scenario, puts downward pressure on prices and the Brent price declines to 2020US$40/barrel (bbl)[10] by the end of the projection period, from 2020US$68/bbl in 2021. In the Current Policies Scenario, crude oil prices stay at 2020US$70/bbl over the projection period. In both scenarios, West Texas Intermediate (WTI), a key North American crude benchmark, is 2020US$4.00 lower than Brent in the long term.

Both EF2021 scenarios assume that the Canadian heavy benchmark price is discounted to WTI consistent with the historical average. The WTI-WCS differential is 2020US$12.50/bbl for most of the projection. However, in reality, if future supply available for export approaches and/or exceeds the level of total capacity provided by pipelines and structural rail, this differential could increase significantly. We do not adjust the assumed differential for such dynamics. Figure R.14 in the "Results" section provides an illustration of how tight or constrained pipeline capacity could become in our two scenarios, based on existing pipeline capacity, planned pipeline expansions, and structural rail.

Figure A.4 shows the EF2021 natural gas price assumptions for the Evolving and Current Policies Scenarios. Over the projection period, Henry Hub, a key North American benchmark price, increases gradually reaching 2020 US$3.60/MMBtu by 2050 in the Evolving Policies Scenario, from $3.00/MMBtu in 2021. In the Current Policies Scenario, natural gas prices rise faster, reaching 2020 US$4.40/MMBtu by 2050. This is consistent with greater North American demand growth and LNG export volumes compared to the Evolving Policies Scenario. EF2021 assumes Henry Hub is 2020US$0.90/MMBtu higher than NIT for the majority of the projection. However, the NIT price discount could materially rise if there are periods where pipeline capacity becomes constrained for moving western Canadian natural gas to markets.

[10] This means $40 in USD currency, and adjusted for inflation in real terms with a base year 2020.

Figure A.3:
Brent Crude Oil Price Assumptions to 2050, Evolving and Current Policies Scenarios

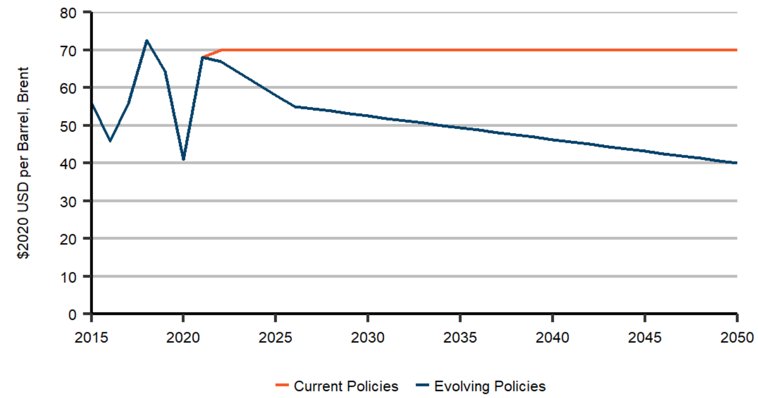
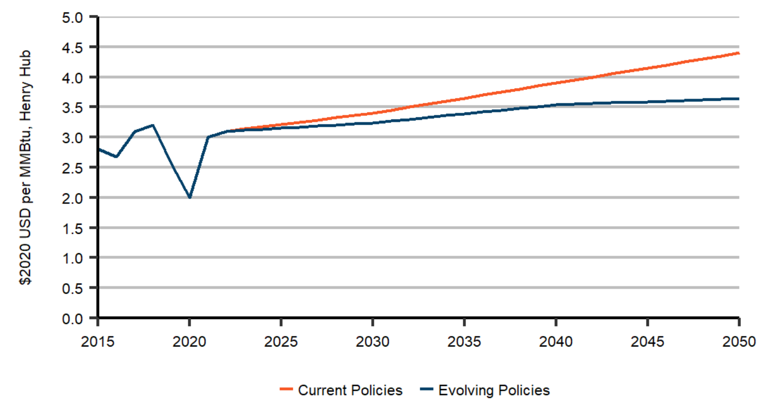


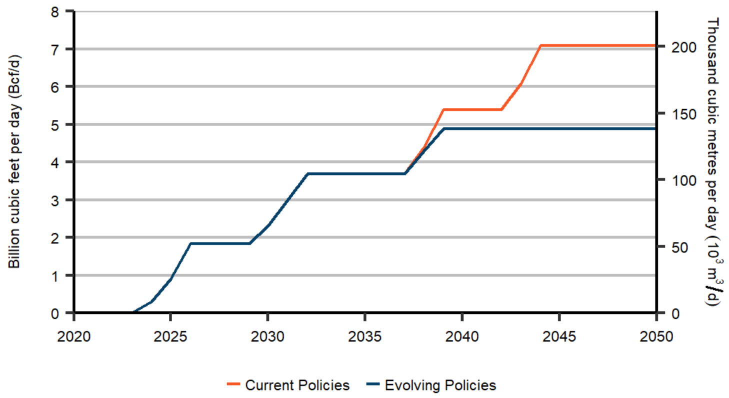
Figure A.4:
Henry Hub Natural Gas Price Assumptions to 2050, Evolving and Current Policies Scenarios



EF2021 assumes LNG export volumes from Canada as shown in Figure A.5. We assume all volumes originate from Canada's west coast. These volumes include Phase 1 of the LNG Canada project, which has a positive final investment decision and is currently under construction. We also include an assumption of additional volumes that are not specific to a particular project. The Current Policies Scenario assumes greater LNG exports than in the Evolving Policies Scenario, beginning in 2039. Future LNG development is uncertain and could be significantly different than implied by these assumptions. For both scenarios, we assume that 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.

Figure A.5:

Canadian LNG Export Volume Assumptions to 2050, Evolving and Current Policies Scenarios



Full benchmark price assumption data and LNG export assumption levels are available in the accompanying data files and appendices, described in the "Access and Explore Energy Futures Data" section.

Electricity

The analysis in EF2021 reflects current utility and system operator expectations of future electricity developments in their respective regions, especially for major planned projects. We also make assumptions on the cost to add new electricity generating capacity in the future. Table A.4 shows assumptions for natural gas, solar, and wind costs, including their capacity factors. Current schedules and plans from utilities, companies, and system operators are the primary basis for the timing and magnitude of other forms of generation added over the projection period (such as hydroelectric and nuclear refurbishments).

As discussed earlier in this section, costs for wind, solar, and other emerging technologies are lower in the Evolving Policies Scenario than the Current Policies Scenario. This assumes a stronger global shift towards these low-carbon technologies, and advancements and efficiencies that continue to lower their costs and improve their performance.

Table A.4:

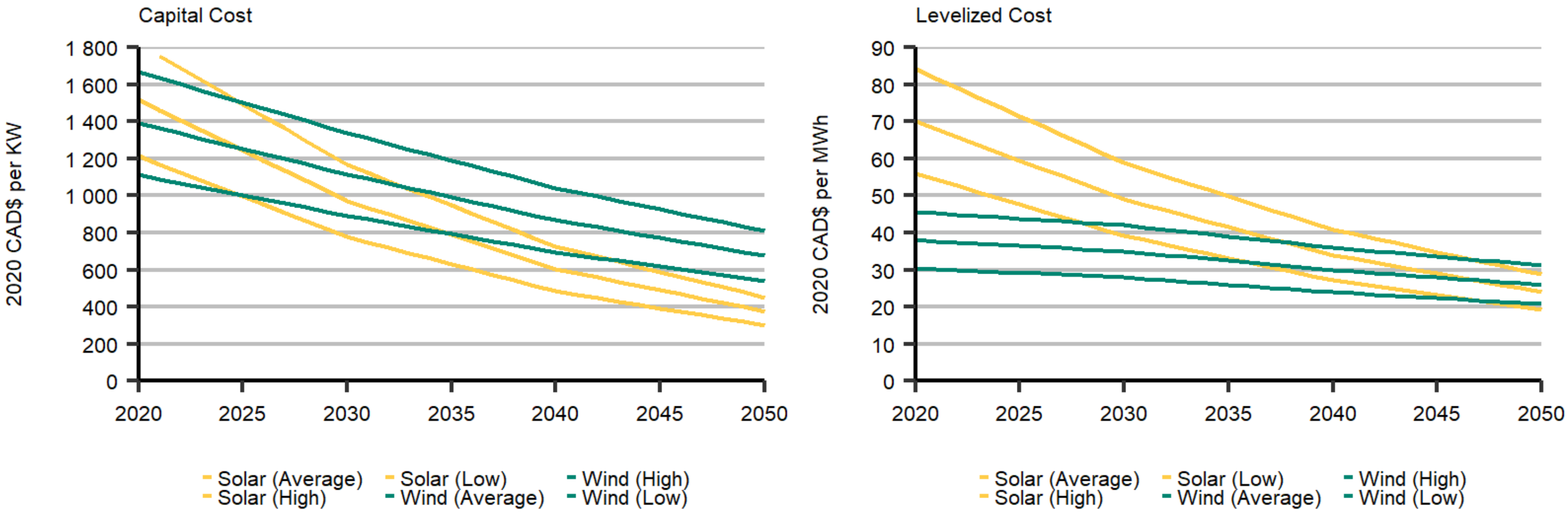
Electricity Cost Assumptions for Natural Gas, Onshore Wind, and Utility Scale Solar to 2050, Evolving and Current Policies Scenarios

	Capital Cost (2020CN $/ kilowatt(kW))	Fixed Operating and Maintenance Costs (2020CN$/kW)	Variable Operating and Maintenance Costs (2020CN$/ megawatt hour(MWh))	Capacity Factor (%)[11]
Gas Combined Cycle (2020-2050, both scenarios)	1 300-1 800	21	5	70
Gas Peaking (2020-2050, both scenarios)	950-1 400	18	5	20
Wind (2020)	1 389	25-60	0	30-45
Solar (2020)	1 516	20-27	0	10-20
Evolving Policies Scenario				
Wind (2030)	1 115	25-60	0	35-55
Wind (2040)	868	25-60	0	35-55
Wind (2050)	676	25-60	0	35-55
Solar (2030)	972	20-27	0	15-25
Solar (2040)	605	20-27	0	15-25
Solar (2050)	376	20-27	0	15-25
Current Policies Scenario				
Wind (2030)	1 226	25-60	0	30-45
Wind (2040)	1 184	25-60	0	30-45
Wind (2050)	1 117	25-60	0	30-45
Solar (2030)	1 066	20-27	0	10-20
Solar (2040)	772	20-27	0	10-20
Solar (2050)	561	20-27	0	10-20

[11] Capacity factors are the actual energy produced by a generator divided by the maximum possible generation over a given period. Capacity factors vary by region and technology, and on average improve throughout the projection period due to improved performance.

Figure A.6:

Wind and Solar Capital Costs and Levelized Cost[12] Assumptions to 2050, Evolving Policies Scenario



12 The range around the capital costs is +/- 20%, which reflects the variability across different estimates of current, and future, wind and solar costs. Costs and performance characteristics can vary across regions and time. The ranges around the levelized costs include the variation in capital costs shown in the figure, ranges in other costs and capacity factors shown in Table A.2, as well as higher and lower project financing costs.

Hydrogen

Hydrogen can be produced from organic compounds such as biomass, natural gas, or coal through various processes. It can also be produced from water via electrolysis. The two main forms of production in EF2021 are electrolysis and natural gas with CCS.

- **Natural gas with CCS:** Currently, the most common method for hydrogen production is steam methane reforming of natural gas. In this method, high-temperature steam reacts with methane to produce hydrogen and carbon dioxide (CO_2). Coupling this method with a CCS technology can produce hydrogen with relatively low CO_2 emissions. Going forward, autothermal reforming (ATR) could have a cost advantage compared to steam methane reforming and could allow for a higher rate of CO_2 capture. The recently announced Air Products project in Alberta is proposing to use an ATR technology for its facility. In our analysis we assume all natural gas with CCS hydrogen production has a capture rate greater than 90%. We also assume that because of proximity to sequestration capacity, hydrogen production from natural gas with CCS is only an option in B.C., Alberta, and Saskatchewan.

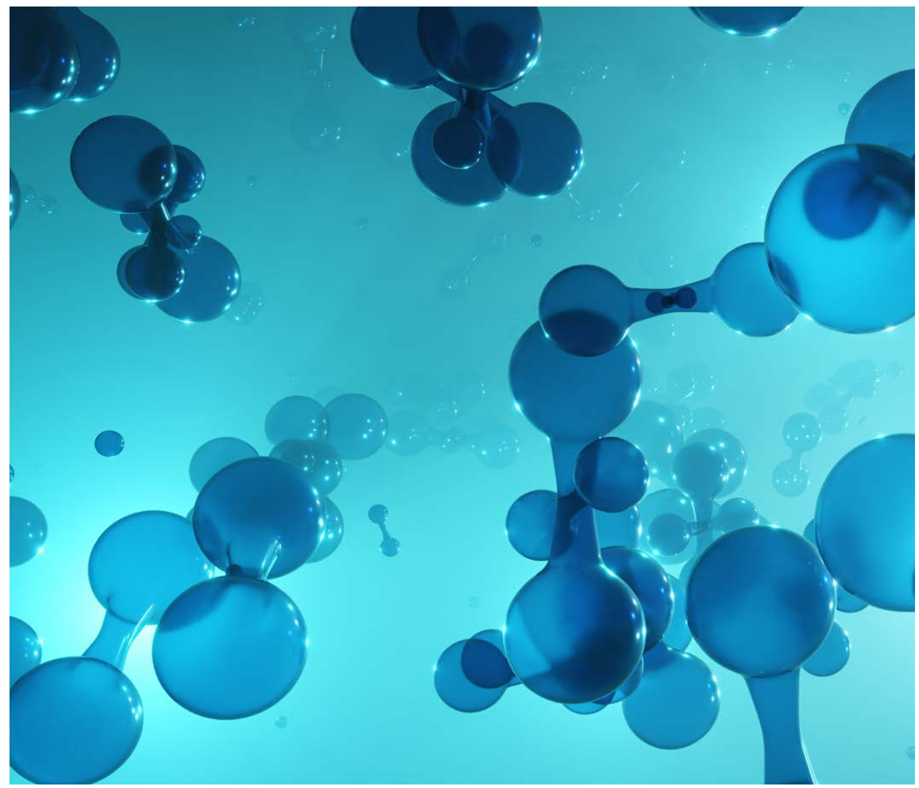
- **Electrolysis:** Electrolysis is a process whereby electricity is passed through water and splits water into its components: hydrogen and oxygen. Depending on the source of electricity, hydrogen produced through this process can have low- to zero-carbon emissions. EF2021 distinguishes between two categories of electrolysis based on how the electricity is supplied: a) grid electrolysis, which uses electricity from the provincial grid at a similar price to industrial users, and b) renewable electrolysis, which utilizes dedicated wind and solar resources.[13] Electrolysis is available in all provinces, and its adoption is based on relative costs.

Hydrogen production cost varies by region and resource availability. The cost of hydrogen production will depend on technology improvements and future electricity and natural gas prices. We assume costs significantly decline in the Evolving Policies Scenario (Table A.6), and remain near current levels in the Current Policies Scenario.

[13] Electricity price is the largest cost component of hydrogen production that uses the electrolysis method. Dedicated renewable electrolysis reduces this cost by producing electricity onsite with the hydrogen production.

Table A.6:
Hydrogen Technology Costs, Evolving Policies Scenario

Cost by Technology type (2020US$/kg)	2020	2030	2040	2050
Electrolysis – Grid	$6.00-8.00	$4.00-7.00	$4.00-$6.00	$4.00-6.00
Electrolysis – Dedicated renewables	$8.00-10.00	$4.00-6.00	$2.00-3.00	$1.50-2.00
Natural Gas with CCS	$1.60-2.00	$1.50-$1.80	$1.50-$1.80	$1.50-$1.70



Given falling costs, as well as other policies such as increasing carbon prices, hydrogen has the potential for adoption across Canada's energy system. The relative economics of hydrogen are a key driver of adoption in the various demand sectors. At the same time, each sector has some other important considerations and uncertainties.

- **Residential and Commercial:** There are physical limits on how much hydrogen can be blended into existing natural gas pipelines and used in conventional end-use devices.[14] To account for this uncertainty we assume maximum blending of hydrogen in the natural gas stream gradually increases throughout the projection period, as infrastructure and technology improves. Maximum blending increases to 3% by volume (1% by energy content) by 2030, 15% by volume (5% by energy content) by 2040, and 20% by volume (7% by energy content) by 2050.
- **Industrial:** Hydrogen demand is modeled on a sector-by-sector level, as industrial sectors have unique characteristics that could influence hydrogen adoption. Certain industries, such as iron and steel, have emerging technologies that are able to incorporate high concentrations of hydrogen as the main fuel. In some industries, such as cement production, it remains more uncertain if significant amounts of hydrogen will be consumable as a low carbon alternative fuel without significantly alerting the final industrial product.
- **Transportation:** As hydrogen costs fall, and carbon prices increase, hydrogen could offer substantial fuel cost savings compared to diesel in freight trucking. Adoption will be determined by other factors as well, such as the cost of hydrogen fuel cell trucks relative to conventional diesel trucks, as well as the development of hydrogen distribution and refuelling infrastructure. We assume fuel cell trucks become cost comparable to diesel trucks around 2035 to 2040, and infrastructure sees widespread deployment from 2035 to 2050 as hydrogen fuel cell trucks gain market share.

We assume that hydrogen is produced within each province to meet local demands, and there is no inter-provincial and international trade. This is an important assumption which affects the results, in that regions with lower cost options for producing low-carbon hydrogen–such as Alberta, with CCS access and announced projects, and Quebec, with relatively low grid electricity prices–are early adopters of the technology. This assumption follows recent hydrogen projects, which are intended for use at the facility where the hydrogen is produced, or in the nearby region. However, large-scale hydrogen trade has been proposed[15] and is still being analyzed. If significant trade between regions occurs, it could alter the production and consumption trends shown in our hydrogen results.

---

[14] Studies by the National Renewable Energy Laboratory and the Transition Accelerator have suggested that current end-use technologies and pipeline infrastructures could handle up to 15% blending by volume.

[15] For example, Alberta's 2021 Hydrogen Roadmap highlights hydrogen exports as a key pillar, potentially by 2030.

Results

This section presents results of the EF2021 projections. The primary focus is the Evolving Policies Scenario. These projections are not a prediction, but instead present possible future outcomes based on the assumptions described in the previous section. There are many factors and uncertainties that will influence future trends. Key uncertainties are discussed in each section.

For a description of the various ways to access the data supporting this discussion, including full data tables for both the Evolving and Current Policies scenarios, see the "Access and Explore Energy Futures Data" section.

Macroeconomics

The economy is a key driver of the energy system. Economic growth, industrial output, inflation, exchange rates, and population growth all influence energy supply and demand trends.

In the near term, the economy continues its gradual recovery from the COVID-19 pandemic. As shown in Figure R.1, total real gross domestic product (GDP) declined 5.3% in 2020 and grows by 5.7% in 2021.

The long-term projections for key economic variables are in Figure R.2. Economic growth (adjusted for inflation) averages 1.6% per year over the projection period in both the Evolving Policies Scenario, and the Current Policies Scenario, with the Current Policies Scenario slightly higher. Economic growth over the projection is generally slower than the 1990 to 2018 historical period for a variety of reasons, including an aging population and slower global economic growth.

KEY UNCERTAINTIES:

Macroeconomics

COVID-19 pandemic recovery: Recovery from COVID-19 is a key uncertainty for global, North American, and Canadian macroeconomic growth.

Global economic growth: Global economic growth affects many factors that are important for Canada's economy, including commodity prices, and demand for Canadian energy and non-energy exports.

Figure R.1:
GDP Growth Rebounds Following a Steep Decline in 2020

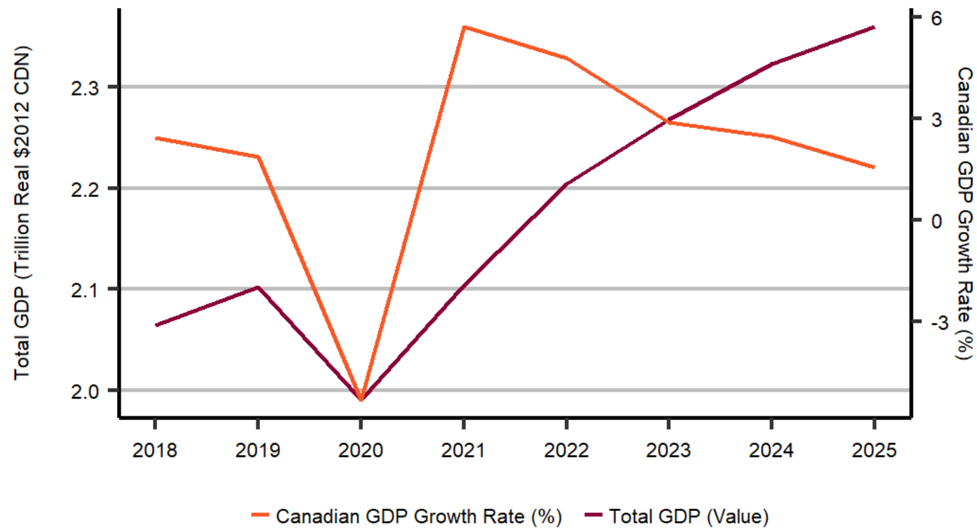
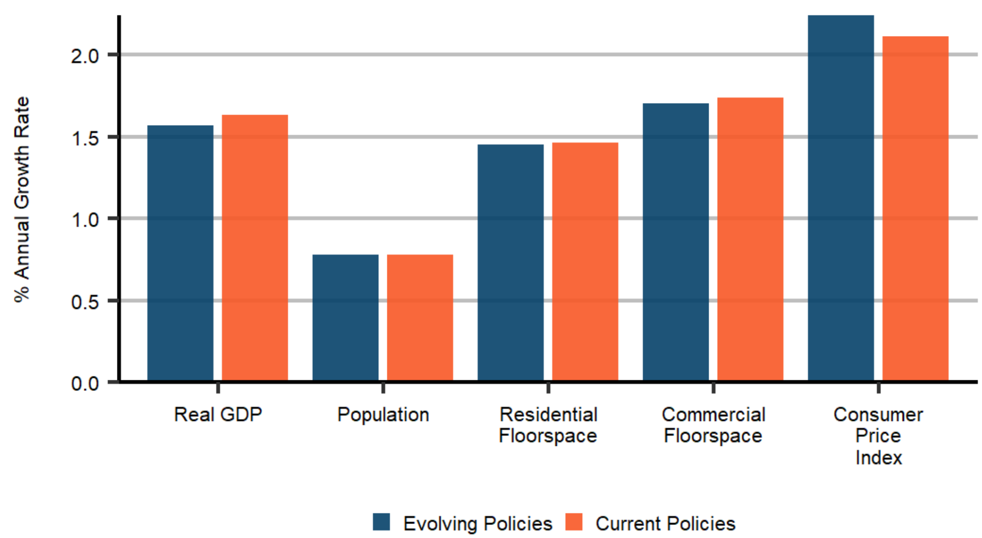


Figure R.2:
Economic Indicators, Evolving and Current Policies Scenarios (2019 to 2050)



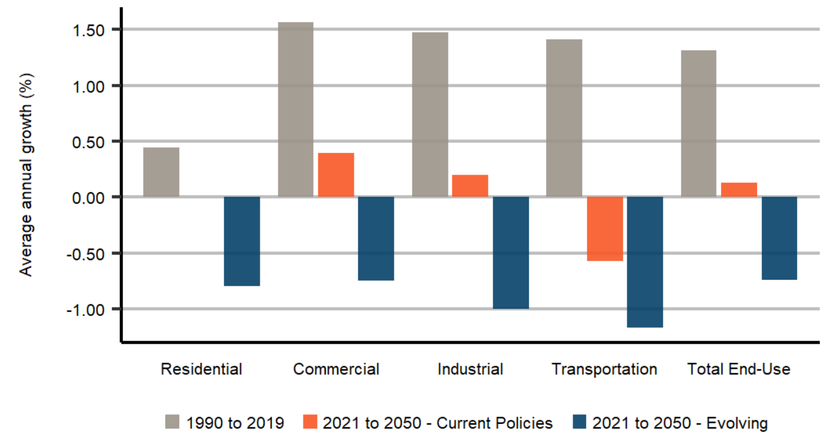
Energy Demand

This section first discusses secondary (or "end-use") energy demand projections by reviewing energy use by sector of the economy, before turning to our economy wide primary energy demand projections. End-use demand includes electricity and hydrogen, while the fuel used to produce electricity and hydrogen is accounted for in primary energy demand. Historical 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 (ECCC), Natural Resources Canada, and various provincial data sources.

In the near term, energy use follows macroeconomic trends. We estimate that demand declined 8% in 2020, and project it to increase in 2021 and 2022. In the long term, the Evolving Policies Scenario projects Canadian energy use to decline to 2050. Figures R.3 and R.4 break energy use down by sector, showing declines in all sectors. The largest declines are in the industrial (including upstream oil and gas) and transportation sectors. These declines are due to factors such as improved energy efficiency, increasing electrification of the transportation sector,[16] and various policies, like carbon pricing. Partially offsetting these factors, economic growth and a near-term increase in crude oil production provide some upward pressure on energy use. However, economic growth is slower than historical trends, and crude oil and natural gas production eventually declines. The Current Policies Scenario sees moderate demand growth over the projection period (though at levels lower than recent history) due to the lack of additional climate policy action beyond current policies, higher crude oil and natural gas production, and less electrification.

[16] On an energy equivalent basis, EVs use less energy to travel a given distance than conventional vehicles. As EVs gain market share, the offsetting reduction in gasoline demand will be larger than the electricity added, leading to a net reduction of energy consumption. Additional details on EV efficiency and economics can be found in CER Market Snapshot: Levelized Costs of driving EVs and conventional vehicles.

Figure R.3:
End-use Demand Declines in All Sectors in the Evolving Policies Scenario



KEY TRENDS:
Energy Demand

- Total energy use declines in the Evolving Policies Scenario and grows slowly in the Current Policies Scenario.
- Growth rates for end-use demand by sector are lower than in the past for both scenarios.
- The mix of energy sources that Canadians use continues to change in the Evolving Policies Scenario, shifting towards a majority of low- or non-emitting energy sources in the longer term.
- In the Evolving Policies Scenario, energy use declines while population and GDP continue to grow, resulting in a significant decline in energy use per person and per dollar of economic activity.

Energy use trends vary by sector and by energy type in the Evolving Policies Scenario (See Figure R.5). These trends result from many different drivers, including macroeconomics, energy production trends, energy efficiency improvements, policies, technology advancements, and market developments. Highlights include:

- In the residential and commercial sectors, improving efficiency of devices and building envelopes reduces overall energy consumption. Rising carbon prices and improving technology drive penetration of heat pump technology in buildings, reducing natural gas use. Blending of renewable natural gas and hydrogen into natural gas streams also reduces natural gas use. This is driven by a combination of policy assumptions (see the "Scenarios and Assumptions" section), and economics in the longer term as carbon prices increase and technology costs fall.

- In the industrial sector, trends vary by industry. The oil and gas sector becomes more efficient, and production growth slows and eventually peaks for crude oil production, while natural gas production stays relatively steady and then declines. Solvent-assisted production in in situ oil sands helps improve energy intensity significantly in the latter half of the projection period. In the longer term, hydrogen reduces natural gas use, especially in key sectors such as iron and steel, cement, refining, as well as the oil and gas sectors. At the same time, increasing use of CCS puts upward pressure on energy demand as the CCS process requires energy.

- The transportation sector undergoes a notable low-carbon transition. Refined petroleum products (RPPs) like gasoline, diesel, and jet fuel have historically dominated the transportation sector, and this begins to change in the Evolving Policies Scenario. The Evolving Policies Scenario assumes that the recently announced Federal goal for all new vehicle sales to be ZEVs by 2035 is achieved, and that adequate supplies of battery and plug-in hybrid electric vehicles will exist and meet demand.[17] This substantially reduces gasoline demands in the projection. Electric freight, particularly light-to-mid-duty, hydrogen-powered freight (mid-to-heavy duty), and increasingly electrified public transportation (electric bussing) grow steadily in the 2030s and 2040s. Biofuels blending into gasoline and diesel increases from current levels in both scenarios, driven by policies like the Federal Clean Fuel Regulation.

[17] Electricity demand associated with electric vehicles is included in the transportation sector in these projections, although large amounts of at-home charging are likely to occur.

Figure R.4:

End-use Energy Consumption Peaks in 2019 and Declines over the Long Term in the Evolving Policies Scenario

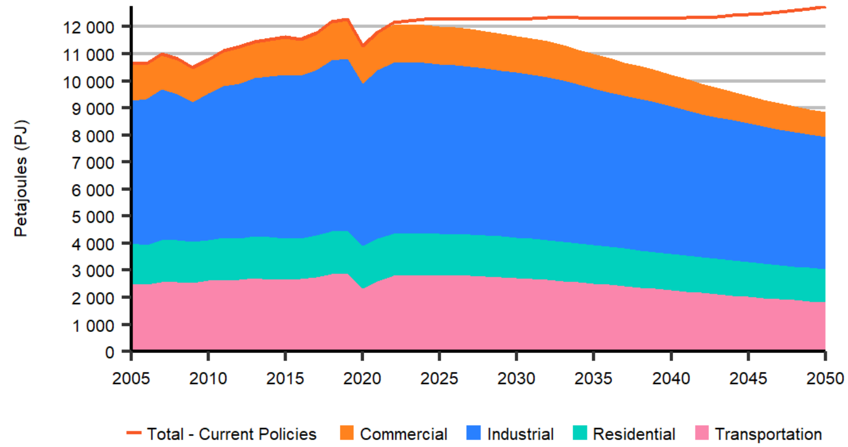
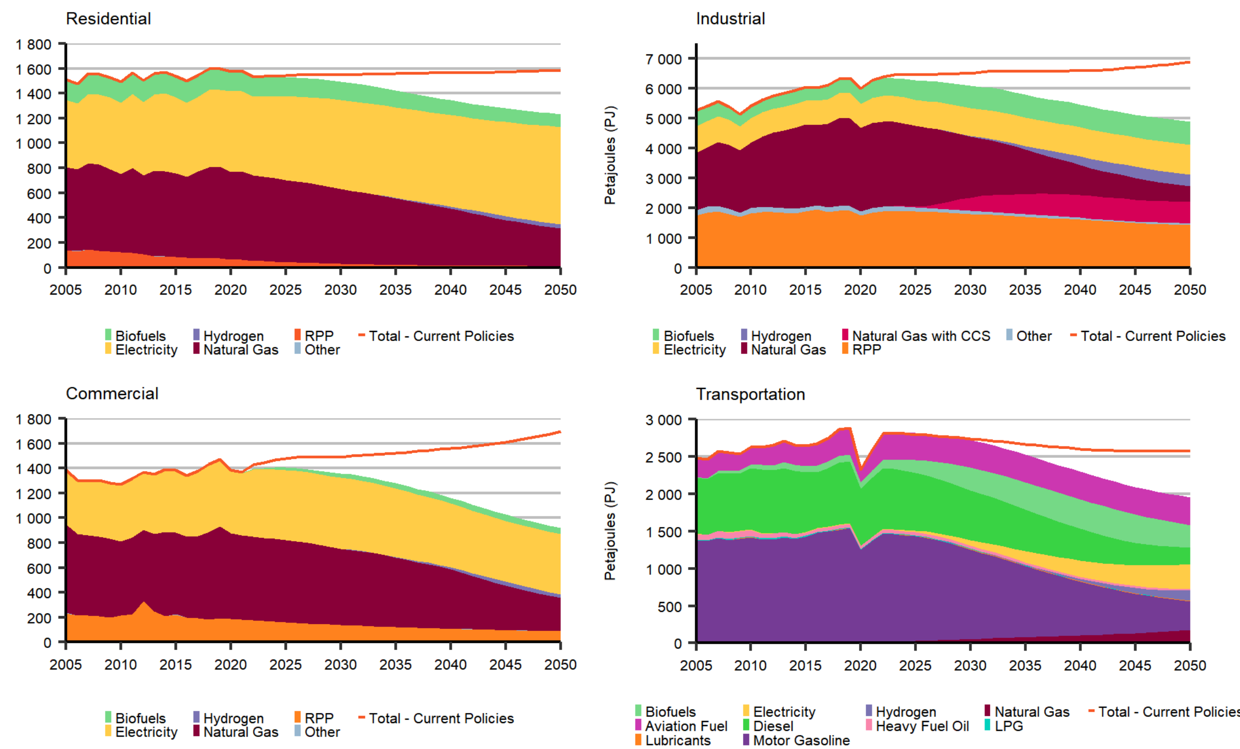


Figure R.5:

End-Use Energy Demand Trends Vary by Sector and By Fuel in the Evolving Policies Scenario



In this analysis, primary demand is the total amount of energy used in Canada. Primary demand is calculated by adding the energy used to generate electricity and hydrogen to total end-use demand, and then subtracting the end-use demand for electricity and hydrogen. Primary demand is higher than end-use demand due to factors such as heat loss in thermal electric generation, and the energy required for the hydrogen production process. This implies that it takes more than one unit of natural gas or coal to produce the same energy unit of electricity, and similarly more than one unit of natural gas or renewables to produce one energy unit of hydrogen.

Figure R.6 shows primary demand by fuel for the Evolving Policies Scenario, compared with total primary demand in the Current Policies Scenario. In the Evolving Policies Scenario, total demand gradually falls, driven by declining fossil fuel use. Coal demand declines considerably due to the phase-out of coal-fired power generation. RPP demand falls along with improving energy efficiency and electrification of the transportation sector. Demand for non-energy oil products, such as asphalt, lubricants, and feedstocks are relatively stable. Natural gas demand grows slowly to about 2025, driven by increasing crude oil production as well as its increasing role in power generation. From 2025 to 2050 total natural gas demand steadily declines, as less is used for crude oil and natural gas production (due to both increased efficiency and, eventually, less production), energy efficiency improves, renewables replace some natural gas in power generation, and renewable natural gas and hydrogen are blended into the natural gas stream. Increasing natural gas use to produce hydrogen, as well as adding CCS to natural gas use in industrial electricity generation and power, partially offsets this decline.

Driven by increased electrification at the end-use level, overall electricity demand rises steadily in the Evolving Policies Scenario. This demand leads to stable production of nuclear power and growth in renewable power as major hydro projects are completed, and wind and solar costs continue to fall. Renewables become an increasingly important part of the energy mix. Increased blending of renewable fuels in liquid fuels and natural gas also support increasing renewable demand.

Energy use falls while both the economy and Canada's population grow, implying that energy intensity–measured in energy use per capita or per $ of real GDP–declines significantly. This is shown in Figure R.7. From 2019 to 2050, real GDP increases 60% and population increases over 27% in the Evolving Policies Scenario. Primary energy use declines 25%. These different trends imply that energy use per $ of real GDP declines over 50% from 2019 to 2050, while energy use per person declines over 40% in the Evolving Policies Scenario.

Figure R.6:

Primary Demand Gradually Declines and Renewables Account for a Larger Share in the Evolving Policies Scenario Energy Mix

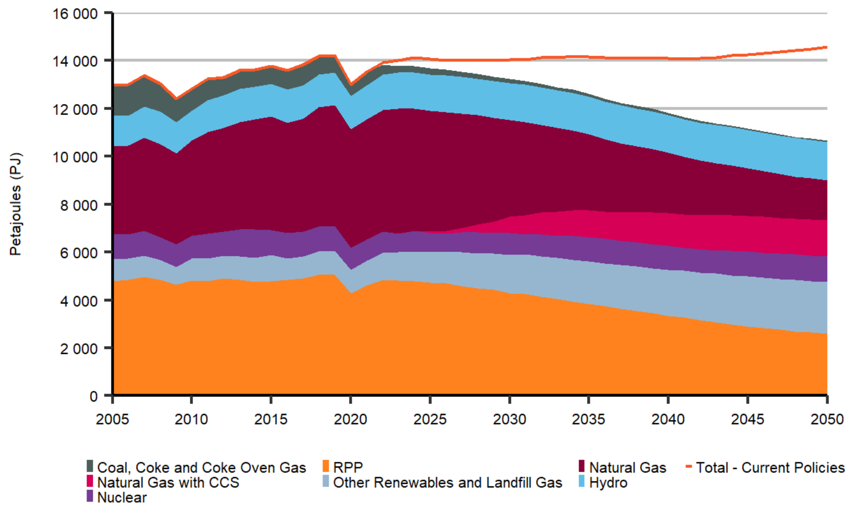
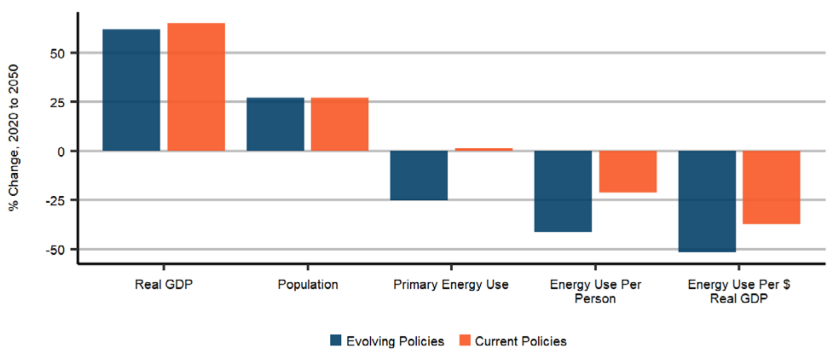


Figure R.7:

The Economy Grows Faster than Energy Use, and Energy Intensity Declines in both the Evolving Policies Scenario and the Current Policies Scenario



KEY UNCERTAINTIES:

Energy Demand

Future policy changes: In December 2020, Canada announced a significant increase to its carbon pricing pathway, and revisions to the proposed Clean Fuel Standard (published in the Canada Gazette as the Clean Fuel Regulation). Canada has recently committed to a stronger 2030 target in its Nationally Determined Contribution submitted to the United Nations, and announced intentions for 100% of passenger vehicle sales to be ZEVs by 2035. These changes illustrate how dynamic climate policy has been in recent years. This may continue if urgency and ambition to reach climate targets increases. Future policy changes will have significant impacts on energy projections.

Technological influences: The impacts of technology on the energy system are substantial and can be difficult to predict. The Evolving Policies Scenario continues the momentum for increased use of established technologies and allows for the adoption of emerging technologies currently near commercialization. The pace, types, and costs of new technological adoption are highly uncertain and likely to be different from those assumed and modelled in our scenarios.

Alternative fuels and new end-uses: Both core scenarios show a shift towards electricity, supported by the increasing use of renewables. They also feature increasing adoption of low-carbon fuel alternatives, such as hydrogen, renewable natural gas, and liquid biofuels, to varying degrees. Faster electrification of the economy, or investment and growth in alternative fuels production could lead to different trends compared to those shown here.

Crude Oil

Crude oil is produced in Canada for domestic refining as well as for export. In 2019, Canadian crude oil production averaged 4.9 million barrels per day (MMb/d) (784 thousand cubic metres per day (10^3m^3/d)). Production declined by 5% in 2020, largely due to the COVID-19 pandemic, but had returned to 2019 levels by the end of 2020. In recent years, most production growth has been concentrated in the oil sands. Regionally, most production is in Alberta, with additional volumes in Saskatchewan and offshore Newfoundland and Labrador.[18]

Figure R.8 shows Canadian crude oil production by type in the Evolving Policies Scenario, compared to total Current Policies Scenario production. Canadian crude oil production in the Evolving Policies Scenario peaks at 5.8 MMb/d (930 10^3m^3/d) in 2032 and declines to 4.8 MMb/d (756 10^3m^3/d) in 2050, a decrease of 4% from 2021. For comparison, production peaks at 6.7 MMb/d (1064 10^3m^3/d) in 2044 in the Current Policies Scenario, driven by higher crude oil price assumptions and other assumptions related to the lack of future domestic and global climate policy action.

Production growth in the oil sands continues in the near term, peaking in 2032 and declining slightly through 2050 in the Evolving Policies Scenario. Figure R.9 shows Evolving Policies Scenario oil sands production by type, while Figure R.10 shows it by vintage. Growth is dominated by in situ projects. Most production growth in this scenario are expansions to existing projects, which are profitable given Evolving Policies Scenario price levels and technology improvements that increase productivity.

[18] Information on crude oil ultimate potential and remaining reserves is available in the EF Data Appendices.

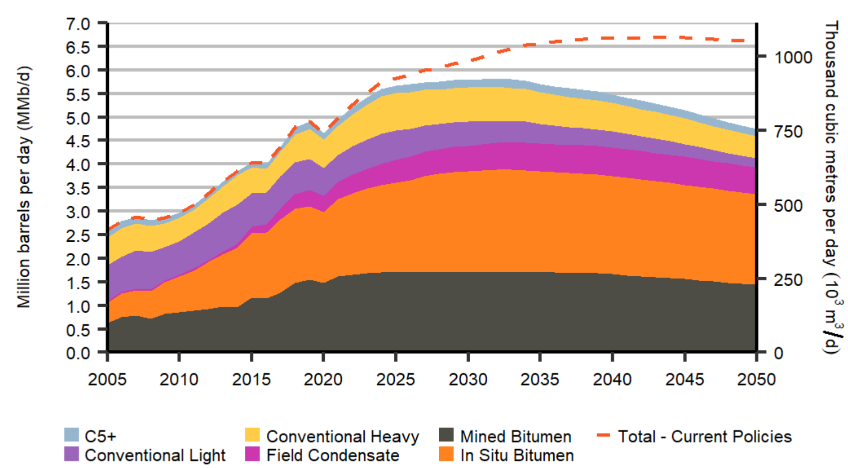
KEY TRENDS:

Crude Oil Production in the Evolving Policies Scenario

- Production grows through the start of the projection period with most growth occurring before 2025. After this point, production is relatively flat and peaks in 2032 at just under 5.8 MMb/d, before declining to 4.8 MMb/d in 2050. This compares to production of 5.0 MMb/d in 2021. Price assumptions underpin this growth. Longer term, assumptions of lower crude oil prices and increasing carbon costs lead to declines in production.
- From 2019 to 2032, crude oil production increases 19%. Between 2032 and 2050 production decreases by 19%.
- In situ bitumen production grows to 2.2 MMb/d in 2032 before declining to 1.9 MMb/d by 2050, from 1.7 MMb/d in 2021.
- Mined bitumen production peaks in 2024 at 1.7 MMb/d, declining thereafter to 1.4 MMb/d by 2050, from 1.6 MMb/d in 2021.

Figure R.8:

Total Crude Oil Production Peaks in 2032 and then Declines through 2050 in the Evolving Policies Scenario



[Conventional](#), [tight](#), and [shale](#) production is classified as [light](#) or [heavy](#), depending on the [API gravity](#) of the oil. In 2020, 51% of western Canadian conventional production was heavy and 49% was light. Near-term growth in production in these categories is primarily due to increases in light oil production in Alberta, along with growing heavy oil production in Saskatchewan. Light oil, particularly tight oil, growth is based on producers' preference to target wells which have higher initial production rates and a quicker return on investment. Growth in Saskatchewan's heavy oil production is due to the low cost and low decline rates of heavy oil reservoirs in the province (Figure R.11).

The majority of condensate production has and is projected to come from Alberta. Growth in condensate production in the projection period occurs in Alberta and B.C., as producers focus on liquids-rich natural gas plays like the Montney Formation and the Duvernay (Figure R.12). Condensate is used as a diluent for bitumen and heavy oil.

Newfoundland offshore production in the Evolving and Current Policies scenarios steadily declines as shown in Figure R.13. We assume no new discoveries in the Evolving Policies Scenario. Additional discoveries and developments could change these trends. In the Current Policies Scenario, we assume new discoveries are made and start producing oil beginning in 2032.

Figure R.9:

Oil Sands Production Peaks in 2032 and then Declines Throughout the Projection Period in the Evolving Policies Scenario

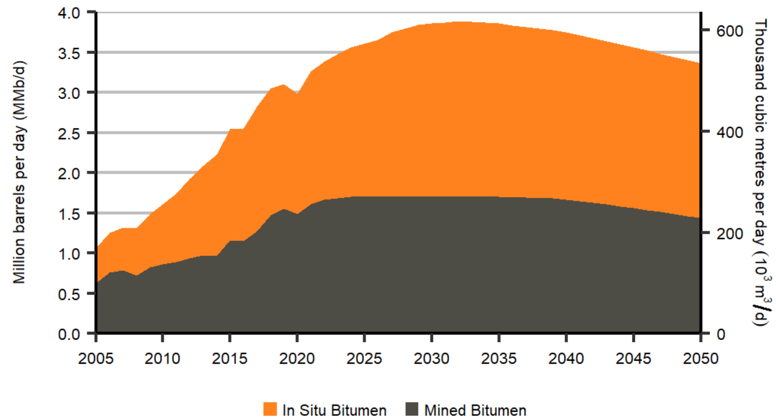


Figure R.10:

Oil Sands Production: Existing vs. Projected Additions in the Evolving Policies Scenario

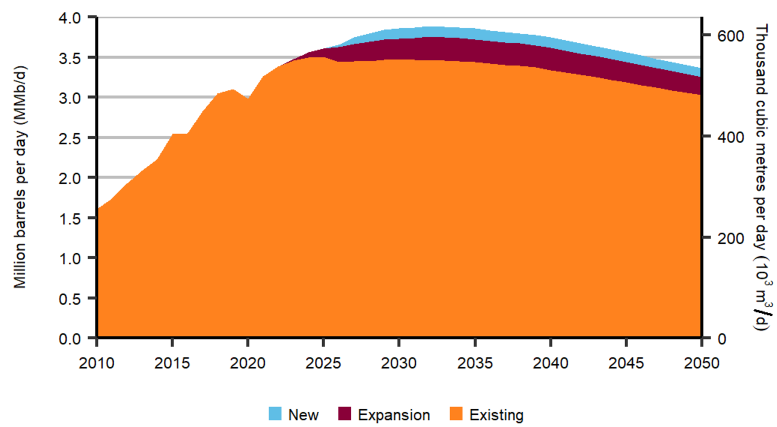


Figure R.11:

Conventional, Tight, and Shale Oil Production Decreases Steadily over the Projection in the Evolving Policies Scenario After a Brief Increase Over the Next Five Years

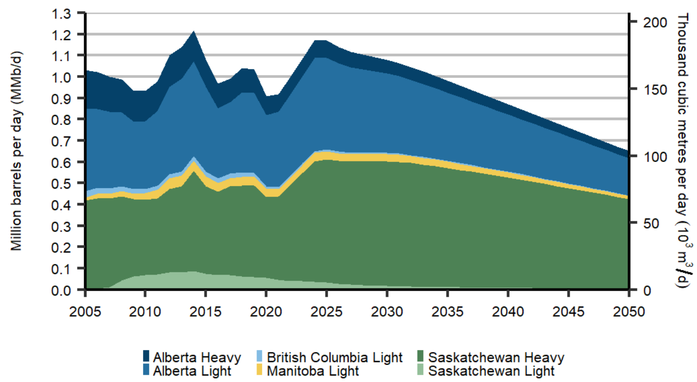
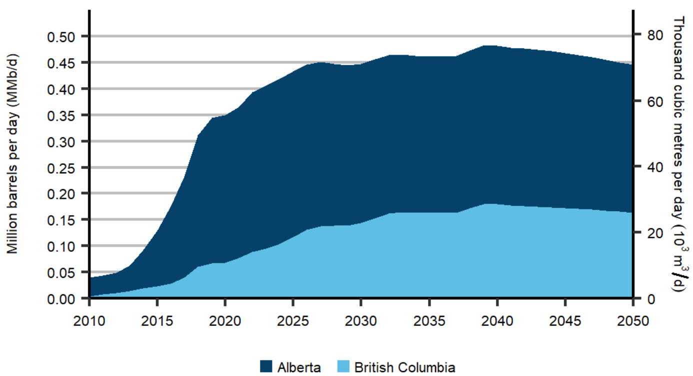


Figure R.12:

Condensate Production Driven by Increasing Diluent Demand in the Evolving Policies Scenario



New Technology in Oil Sands Production

In the Evolving Policies Scenario, we assume that technological improvement in extraction and upgrading methods of existing oil sands projects continues at the same pace as recent history. Although uncertainties exist, the improvements have the potential to reduce the per-barrel costs to produce bitumen, offsetting the higher carbon costs and lower commodity prices. These improvements also lead to lower per barrel emissions.

Much of the growth in oil sands production is in the form of expansions to existing facilities. By the end of the projection, facility expansions make up 7% of all oil sands production, or just over 0.23 MMb/d. Growth also comes from new facilities. No new oil sands mining or upgrading facilities will be created over the projection period. However, new in situ facilities make up 4% or 0.11 MMb/d of total oil sands production from 2019 to 2050.

We assume new or expanded facilities, which begin production after 2025, use the following technologies to lower their emissions intensity:

Steam and pure solvents: The injection of heated solvents (typically a mixture of natural gas liquids (NGLs)) into the reservoir to replace the steam generation units currently in use, lowering emissions. This process also leaves some of the less desirable components within bitumen (asphaltenes) in the reservoir. Pure solvents have the potential to reduce per-barrel operating costs by up to $3.50 per barrel.

In-pit extraction: A technique currently being developed by Canadian Natural Resources Limited at its Horizon Oil Sands mine, which involves separating oil sands ore into its component parts within the extraction pit of the operation. This method requires comparatively less heavy equipment and electric power, resulting in less emissions per barrel, and a potential cost savings of $2.00 per barrel.

Figure R.13:
Newfoundland Offshore Oil Production Steadily Declines to 2050 in the Evolving Policies Scenario

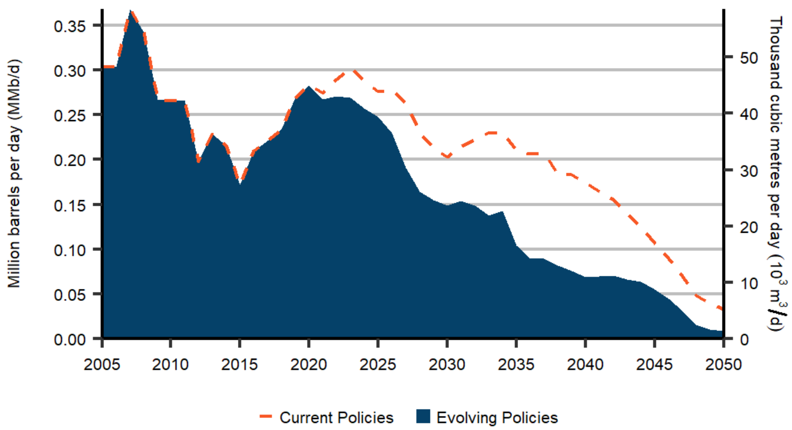
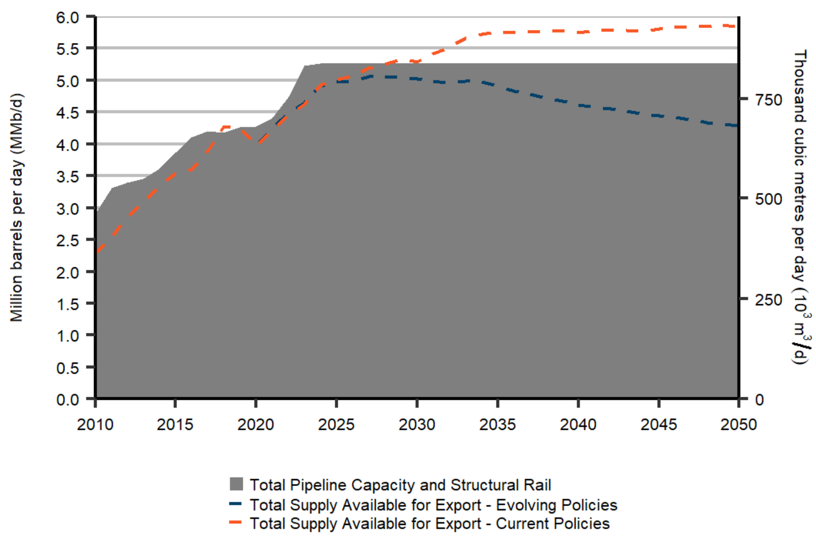


Figure R.14:
Illustrative Export Capacity from Pipelines and Structural Rail, vs. Total Supply Available for Export in the Evolving and Current Policies Scenarios



A key issue for Canada's energy system over the last number of years was the availability of crude oil export pipeline and rail capacity. This has implications for Canadian oil pricing and production trends. When total export capacity is very full, it can lead to widening differentials, particularly when there are unexpected outages. Figure R.14 is an illustrative comparison of our crude oil supply projections and the level of total export capacity that would be provided by existing pipeline capacity, planned pipeline expansions, and structural rail.[19] Making this comparison allows us to get an understanding of whether pipeline constraints might impact crude oil production in our scenarios. However, we do not adjust our crude oil production projections based on potential constraints.

In the Evolving Policies Scenario, crude oil available for export from western Canada stays below the total hypothetical export capacity throughout the projection period. However, into the mid-2030s the difference between capacity and supply is small. EF2021 does not assess whether in this scenario, additional pipeline capacity would be required to avoid constraining Canadian crude oil production below what is projected throughout the projection period.

In the Current Policies Scenario, supply exceeds capacity through much of the projection period. This clearly suggests that without additional pipeline capacity, production would be constrained below what is projected.

EF2021 does not explore the complexities of how pipeline infrastructure interacts with energy supply and demand outcomes. For example, some spare pipeline capacity can benefit crude oil producers by providing flexibility to access higher value markets or avoid the impacts of maintenance or unforeseen outages. It's also possible that excess capacity and long-term underutilization of pipelines could result in higher pipeline tolls for crude oil producers. Analysis of these considerations is beyond the scope of EF2021. We caution readers from drawing definitive conclusions from the illustrative comparison shown Figure R.14.

It is also important to note that the estimate of what total available pipeline capacity and the level of structural rail could be is uncertain and the result of many key assumptions. Table R.1 describes the infrastructure assumptions that underpin Figure R.14. Available capacity on existing pipeline systems could be higher or lower than reflected in Figure R.14, as pipeline systems evolve over time. The level of structural crude by rail could also be somewhat higher or lower than reflected in this figure.

[19] Structural rail refers to crude oil that is exported by rail regardless of a given WCS-WTI differential. Companies may choose to export crude oil by rail in this way due to a number of factors. These include existing contractual commitments, ownership of the crude-by-rail infrastructure, and the need to access locations not well connected by pipeline.

Table R.1

Pipeline Capacity Assumptions for Figure R.14

Name	Takeaway Capacity (current or timing as noted) (Mb/d)	Notes
Enbridge Mainline	3 207	Stated capacity includes the fully completed Line 3 Replacement Project which adds 370 Mb/d of capacity to the Enbridge Mainline in late 2021.
Keystone	586	Capacity held fixed over the projection period. The cancelled Keystone XL project is not included in Figure R.14.
Trans Mountain	300	Capacity is held fixed over the projection period. This capacity approximates the crude oil portion of capacity, by removing 50 Mb/d from the full capacity of Trans Mountain (350 Mb/d) to accommodate transportation of 50 mb/d of RPPs on the pipeline.
Trans Mountain Expansion	540	The Trans Mountain Expansion Project adds capacity starting in December 2022, and increases to full capacity by the spring of 2023. As with the existing Trans Mountain system, full capacity of the Trans Mountain Expansion (590 Mb/d) is reduced to accommodate transportation of 50 Mb/d of RPPs.
Express	310	Capacity held fixed over the projection period.
Milk River	97	Capacity held fixed over the projection period.
Aurora/Rangeland	44	Capacity held fixed over the projection period.
Structural Rail	120	Capacity held fixed over the projection period.
Capacity Increases to Existing Pipelines	58	Includes announced optimizations to boost the capacity of existing pipelines. The capacity increases are reflected in 2021 to 2023.
Total	**5 262**	

KEY UNCERTAINTIES:

Crude Oil Production in the Evolving Policies Scenario

Future crude oil demand: As climate policy announcements and ambitions increase around the world, many global scenarios have shown a significant reduction in global crude oil demand. These reductions may be needed to meet Paris climate goals of keeping temperature increases to well below 2 degrees Celsius, and to preferably limit warming to 1.5. If these ambitions are realized, falling crude oil demand could have significant impacts on market prices and investment that would affect future Canadian hydrocarbon production (see box "Global fossil fuel market dynamics and implications for Canadian production trends").

Technological development in the oil sands: Reducing GHG emissions and costs are two significant factors in the future development of oil sands facilities. Technologies are currently being developed to address both aspects, although their future adoption is uncertain. As in previous editions of *Canada's Energy Future*, EF2021 assumes that companies continue to work towards lowering both the cost and GHG emissions of their operations.

Western Canadian takeaway capacity: EF2021 assumes that western Canadian crude oil prices will consistently track prices in international markets, consistent with historical averages. The balance between future export pipeline capacity and supply available for export could affect future price relationships and crude oil production levels (see box "Crude Oil Pipelines in Canada's Energy Future" in the Executive Summary).

ESG considerations: The investment community is shifting its attention towards firms that align with their environmental, social, and governance (ESG) performance criteria.[20] The extent and nature to which ESG considerations may alter upstream investment trends could affect future production trends.

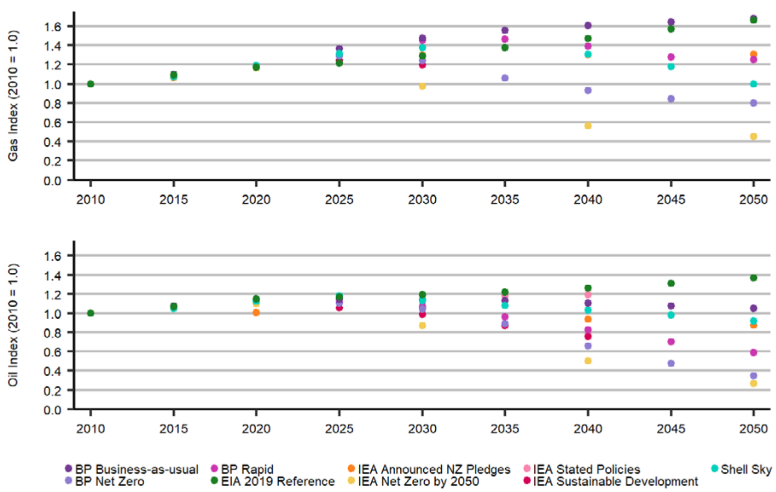
[20] Responsible Investment Association, 2018 Canadian Responsible Investment Opportunity: Trends Report, pg. 12, October 2018.

Global fossil fuel market dynamics and implications for Canadian production trends

The Evolving and Current Policies scenarios explore the impact of changing policy trends, both domestic and global, on the Canadian energy system. The results show that the different assumptions in the scenarios have a large effect on Canadian crude oil and natural gas production projections. This establishes future climate action–particularly global action, which impacts global demand and prices–as a key uncertainty for Canadian production levels. At a high level, the EF2021 production projections have a similar conclusion to global scenario work from the IEA, and companies such as BP and Shell: increasing levels of climate action will decrease production.

Over the past several years, there has been an increasing body of scenario analysis on what net-zero by 2050 means for the global energy system. Figure R.15 shows global oil and natural gas demand trends in a variety of scenarios that vary in their level of decarbonization. The range presented here is large and includes both business as usual and net-zero scenarios. For global oil demand, these scenarios have a range of 37% more to 73% lower compared to current levels by 2050. For natural gas, global demand ranges from 68% more to 54% less relative to current levels by 2050.

Figure R.15:
Growth of Global Natural Gas and Oil Demand, Various International Scenarios by Other Organizations



If the assumptions made in the global net-zero scenarios materialize, there will likely be significant impacts for global crude oil and natural gas markets. In the IEA's Net Zero by 2050 scenario, the global crude and North American natural gas prices are significantly lower than the Evolving Policies Scenario assumptions. The Canadian Institute for Climate Choices Net Zero Report finds that only scenarios with high oil prices and high levels of carbon dioxide removals see Canadian oil production similar to current levels in the long term. These results suggest that in a net-zero world, there could be significant decreases in Canadian oil and natural gas production.

Canadian fossil fuel production in a net-zero world will depend on many factors, such as:

- market prices,
- the evolution of light and heavy oil refinery demand,
- the cost of reducing the upstream emissions of Canadian oil and natural gas production, and
- the extent to which low-carbon natural gas technologies (such as CCS-equipped hydrogen production, electricity generation and industrial use with CCS, and natural gas use for direct air capture) are implemented.

In addition, oil and natural gas production is itself a large user of energy in Canada. As a result, the uncertainty in future production trends is an uncertainty for Canadian energy demand and GHG emissions trends. In the Evolving Policies Scenario, the oil and gas sector makes up about 20% of the remaining unabated fossil fuel demand in Canada in 2050, down from approximately 30% today. The future of global oil and gas trends, and how they affect Canadian investment and production trends, will therefore likely be important for Canada's own net-zero transition.

Natural Gas

In Canada, natural gas is produced for domestic use and exports. In 2020, Canadian marketable natural gas production averaged 15.5 Bcf/d or 438 million cubic metres per day ($10^6m^3/d$).

Natural gas production in Alberta has been relatively flat over the last few years, while B.C. production has been steadily increasing since 2010. This increase has been driven by a variety of factors including:

- Drilling to evaluate natural gas resources expected to supply LNG exports off of Canada's west coast.
- NGLs in the Montney tight gas play driving drilling and production despite lower natural gas prices.
- Horizontal drilling and hydraulic fracturing technological advancements.

In the Evolving Policies Scenario, natural gas production remains near 2020 levels of 15.5 Bcf/d through much of the next two decades. The additional investment in production to meet assumed LNG export volumes sustains production levels. Without these investments, production would otherwise decline, given the assumed North American natural gas prices and the costs associated with assumed domestic climate policies. After 2040, with LNG exports assumed to stay flat, total natural production begins to decline, falling to 13.1 Bcf/d by 2050. Much of the production growth related to LNG exports occurs in B.C., and production in B.C. surpasses that of Alberta by 2028.[21]

In the Current Policies Scenario, natural gas production continues increasing in the longer term, reaching 22.2 Bcf/d (627.4 $10^6m^3/d$) by 2050. Current Policies Scenario projections are driven by assumptions of higher prices, a lack of future domestic and global climate action, and higher LNG exports.

[21] EF2021 projections did not include possible effects stemming from the 29 June 2021 B.C. Supreme Court ruling in Blueberry River First Nations v. Province of British Columbia (Yahey) or the initial agreement reached on 7 October 2021 between B.C. and Blueberry River First Nations addressing, among other things, existing permits and restoration funding. Future analysis will consider any effects as appropriate.

KEY TRENDS:

Natural Gas Production

- Natural gas production is fairly level in the Evolving Policies Scenario to 2040, before declining through the remainder of the projection period.
- Production from the Montney Formation in the form of liquids-rich tight gas grows significantly and becomes the majority of Canadian production over the projection period.

Figure R.16:

Total Natural Gas Production Declines in the Evolving Policies Scenario and Increases in the Long Term in the Current Policies Scenario

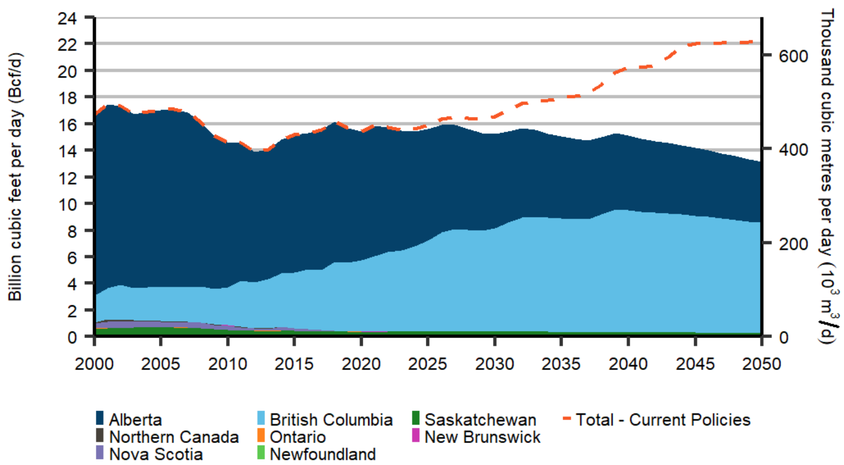


Figure R.17 shows production of natural gas by type in the Evolving Policies Scenario. Production is increasingly made up of tight natural gas produced from the Montney Formation in Alberta and B.C., which has already grown significantly over the past five years. Alberta Deep Basin tight natural gas production declines. There are minimal amounts of shale gas production from the Duvernay and Horn River shales, while solution gas declines and coal bed methane production declines significantly over the projection period.

Figure R.18 illustrates total Evolving Policies Scenario production divided into production that would result from the market prices of the Evolving Policies Scenario, and additional production due to LNG exports. The additional LNG-related production is based on our assumption that 75% of LNG feedstock comes from incremental production that only exists because LNG export capacity exits. The other 25% of LNG feedstock is supplied by the market-driven production (i.e. production that occurs based on assumed North American gas prices). Figure R.18 shows that without additional production to feed LNG exports, production would continuously decline over the projection period to 9.5 Bcf/d (267.7 $10^6m^3/d$) in 2050.

Figure R.17:
Natural Gas Production is Increasingly Made Up of Montney Formation Tight Gas in the Evolving Policies Scenario

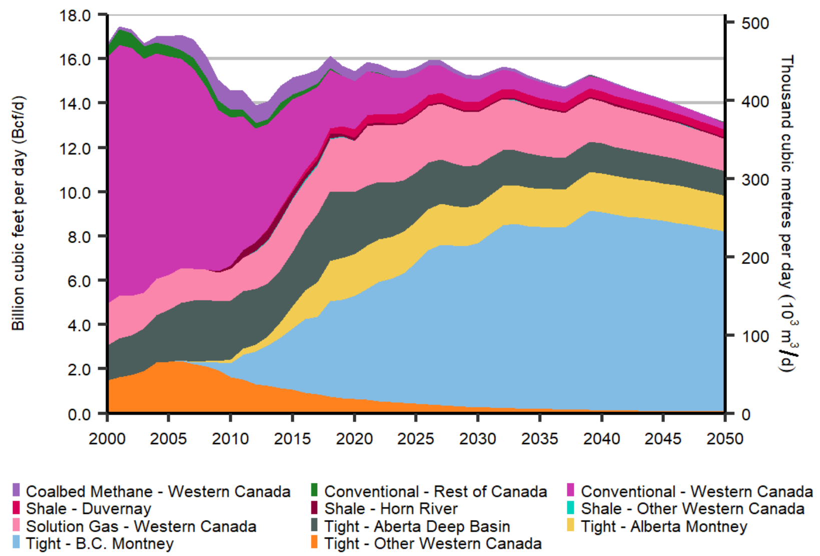
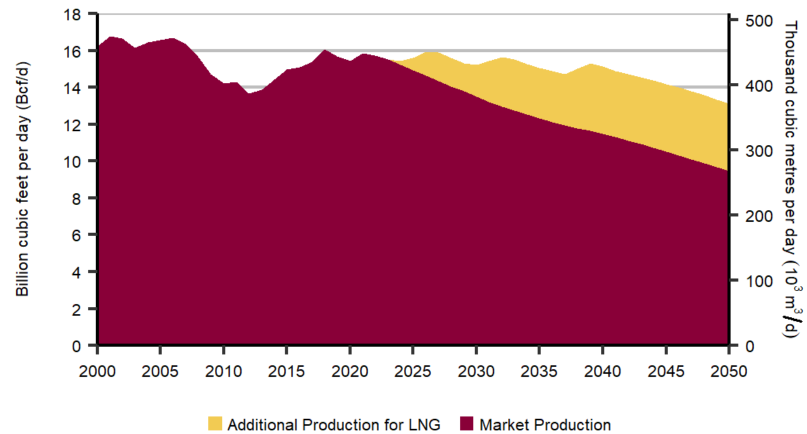


Figure R.18:
LNG Exports Support Natural Gas Production in the Evolving Policies Scenario



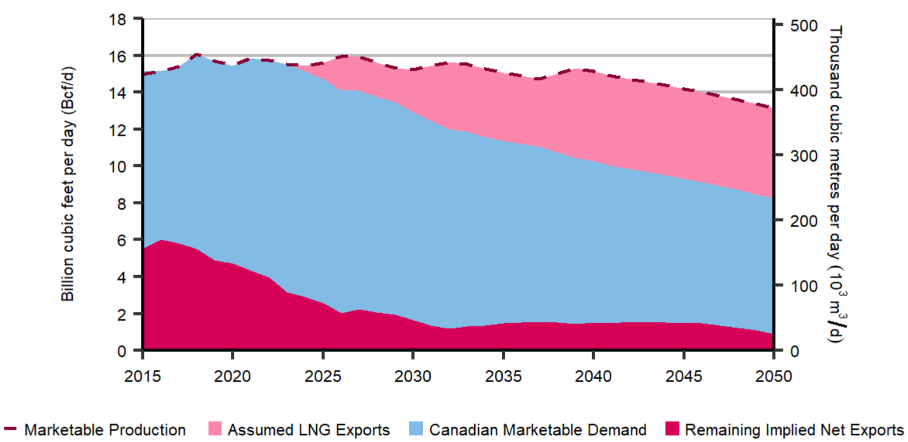
Natural gas exports to the western U.S. have increased over the last several years. Imports to Canada have been relatively steady over the last decade, ranging from 2-3 Bcf/d (57-85 $10^6 m^3$/d). Imports could potentially rise as pipeline capacity increases from the northeastern U.S. to Dawn, Ontario.

Figure R.19 breaks total marketable production in the Evolving Policies Scenario into a) Canadian marketable demand, b) the assumed LNG export volumes, and c) the remaining implied net exports. The remaining implied net exports is mostly by pipeline and calculated as Canadian natural gas production minus Canadian demand and LNG exports.[22] Remaining implied net exports shrink throughout the projection period, resulting from the production, consumption, and LNG export trends discussed earlier in this section. Lower remaining implied net exports do not necessarily mean that non-LNG exports are falling, just that the difference between imports and non-LNG exports is smaller.

[22] This value of natural gas demand is lower than the primary natural gas demand value discussed earlier because it does not include non-marketed natural gas used directly by those that produce it. Examples of this include flared gas, natural gas produced and then consumed by in-situ oil sands producers, and natural gas produced and consumed by offshore oil production.

Figure R.19:

Natural Gas Supply and Demand Balance sees the Increasing Importance of LNG Exports as Domestic Demand Declines in the Long Term in the Evolving Policies Scenario



KEY UNCERTAINTIES:
Natural Gas Production

Future international natural gas prices: Benchmark U.S. prices (i.e. Henry Hub) could be higher or lower, which would lead to different production results under both EF2021 scenarios.

Western Canadian natural gas price discounts: Differentials for western Canadian natural gas relative to Henry Hub could be affected by many factors, including pipeline bottlenecks, and market dynamics. Differentials that vary from what we assume could lead to different production in the longer term.

Future natural gas demand: As climate policy announcements and ambition increase around the world, many global scenarios have shown a significant reduction in global natural gas demand (see textbox "Global fossil fuel market dynamics and implications for Canadian production trends"). If these ambitions are realized, falling natural gas demand could have significant impacts on market prices and investment that would affect future Canadian hydrocarbon production. At the same time, the extent to which natural gas is used for low-carbon hydrogen production and/or direct air capture could impact natural gas demand trends in low-emission scenarios

LNG exports: It is possible that global market conditions and the costs of constructing new LNG export capacity may change in the future, influencing future volumes of LNG exports from Canada in both EF2021 scenarios.

ESG considerations: The investment community is shifting its attention towards firms that align with their ESG performance criteria.[23] The extent and nature to which ESG considerations may alter upstream investment trends could affect future production trends.

[23] Responsible Investment Association, 2018 Canadian Responsible Investment Opportunity: Trends Report, pg. 12, October 2018.

Natural Gas Liquids

Natural gas liquids (NGLs) are produced along with natural gas, as well as from oil sands and refinery processes. Natural gas production is the main source of NGL production in Canada. Demand for certain NGLs adds value to natural gas production and has been a driver of natural gas drilling. Raw natural gas at a wellhead is comprised primarily of methane, but often contains NGLs such as ethane, propane, butane, condensate and other pentanes.

Figure R.20 shows that total NGL production grows around 10% to 2050 in the Evolving Policies Scenario, from the 1 159 Mb/d (184 10^3m^3/d) produced in 2020. Growth is dominated by condensate, which grows 28% by 2050. Condensate, along with butanes, are added to bitumen as a diluent to enable it to flow in pipelines and be loaded on to rail cars. Condensate demand has, and will continue to, influence natural gas drilling to focus on NGL-rich plays.

Propane and butane production declines slightly over the projection period in the Evolving Policies Scenario. Demand for these NGLs increases in the medium term as demand from petrochemical producers in Alberta increases, which may affect export levels of propane and butane.

Additional Detail on Crude Oil, Natural Gas, and NGL Projections

For additional data on crude oil, natural gas and NGL production, see the EF2021 Data Appendices. These datasets include additional geographical and monthly details on production and drilling trends.

Further information about these and other available EF2021 data sets can be found in the "Access and Explore Energy Futures Data" section.

The majority of ethane is extracted at large natural gas processing facilities located on major natural gas pipelines in Alberta and B.C. In 2020, ethane made up 20% of NGL production. Ethane production is flat in the Evolving Policies Scenario, as its recovery from the natural gas stream is constrained by the capacity of the ethane extraction and petrochemical facilities in Alberta, which is assumed to remain constant. Ethane produced in excess of this capacity is reinjected back into the natural gas pipeline system to be consumed by end-users as natural gas, and these volumes do not count in our ethane production numbers.

In the Current Policies Scenario, total NGL production grows 70% to 1 967 Mb/d (313 10^3m^3/d). NGL production growth is due to natural gas production growth in this scenario. Condensate also has the most significant growth in this scenario–growing 121% over the projection, from 349 Mb/d (56 10^3m^3/d) in 2020 to 770 Mb/d (122 10^3m^3/d) in 2050.

Figure R.20:

Condensate has an increasing share of NGL Production in the Evolving Policies Scenario

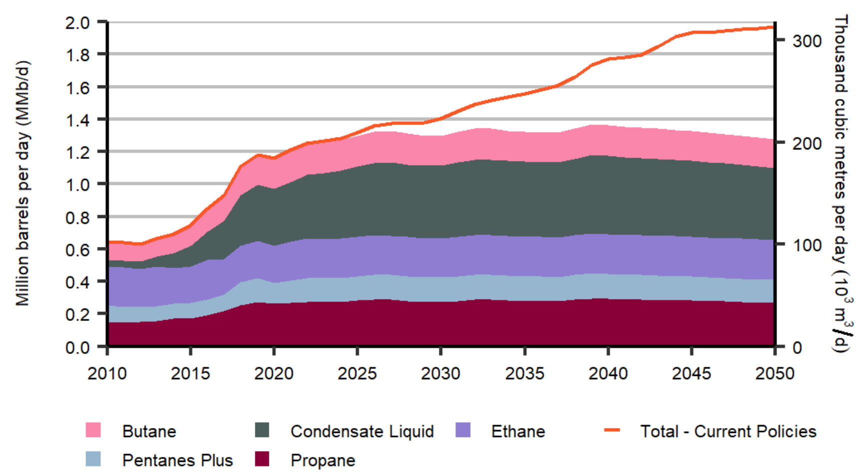


Figure R.21:
Ethane Potential

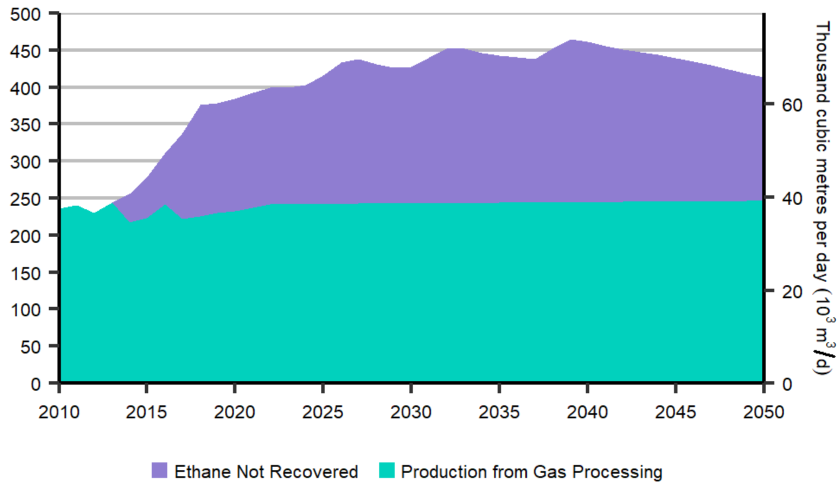


Figure R.22:
Propane Disposition

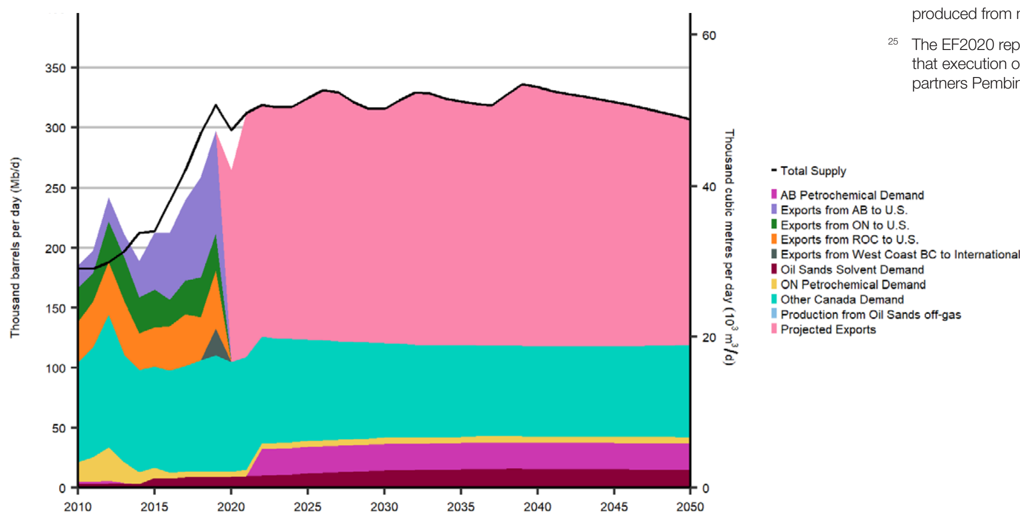


Figure R.21 shows ethane that is extracted from the natural gas stream, and ethane that is not recovered (which includes ethane reinjected in the natural gas stream). Growth in ethane that is not recovered means there is growing potential to recover more ethane, in the event of future increases in the capacity of the ethane extraction and petrochemical facilities.[24]

Figure R.22 shows total propane production broken out into its disposition. There are various uses of propane in Canada in all sectors, and over the next few years, petrochemical demand is projected to increase with the start of The Heartland Complex.[25] Propane exports to the U.S. have grown significantly this past decade as U.S. domestic demand and propane exports *from* the U.S. grew. In 2019, propane exports from the west coast of B.C. began, in the form of liquefied petroleum gas (LPG). These west coast exports could continue to increase, with potential for significant additional LPG projects and exports. Given recent export growth trends, and potential for petrochemical growth above what is projected, the Canadian propane market could see tightening in the longer term if propane production levels off then slightly declines, as projected in the Evolving Policies Scenario.

---

[24] In May 2021 Wolf Midstream announced a positive final investment decision on the NGL North project, anticipated to be in-service in 2023 subject to regulatory and environmental approvals. This project in Alberta would recover up to 70 000 b/d of liquids. This project is not included in either scenario, and if it comes into operation it would increase ethane produced from natural gas processing.

[25] The EF2020 report had a larger value for future Alberta petrochemical demand, but EF2021 has been updated to reflect that execution of one of the two proposed petrochemical complexes was suspended in late 2020, by joint venture partners Pembina Pipeline Corp. and Kuwait's Petrochemical Industries Co.

KEY UNCERTAINTIES:
Natural Gas Liquids

Natural gas: NGLs are a byproduct of natural gas production, and as such, any uncertainty discussed in the natural gas section applies for NGL projections.

Oil sands: The rate of oil sands and other heavy oil production growth, and the amount of blending, will affect the demand for condensate and butanes required for diluent. Likewise, the increased use of solvents to reduce steam requirements in the oil sands would increase demand for propane and butanes, and could influence how much they are targeted by future natural gas drilling.

Petrochemical development: There is potential for ethane recovery to increase further if there is an increase in the capacity of ethane extraction and petrochemical facilities. This could be spurred by government programs, such as royalty credit incentives for petrochemical facilities in Alberta's Petrochemicals Diversification Program.

Global LPG export market: Several large-scale facilities have been approved by provincial and federal regulators to export LPG from B.C.'s coast. Propane exports from the B.C. coast began in May 2019 and butanes also became part of the LPG mix in April 2020. Over the outlook period, propane will likely be the majority of exported LPG. The amount and composition of the LPG stream exported at proposed and existing terminals could impact domestic NGL prices and the attractiveness of drilling for NGL-rich natural gas.

Electricity

In the Evolving Policies Scenario, electricity demand grows by 47% from 2021 to 2050, as shown in Figure R.23. This is driven by growth in all sectors, with transportation and hydrogen production being emerging growth areas. In transportation, electrification provides an alternative in a sector long-dominated by RPP use. Hydrogen production is another growth area for electricity demand, as electricity is used in electrolysis to produce hydrogen.

Currently, electricity makes up approximately 16% of Canada's end-use energy demand. In the Evolving Policies Scenario, end-use electricity demand (excluding electricity to produce hydrogen) increases at an average annual rate of 1% over the projection period, which raises electricity's share of end-use demand to nearly 30% by 2050. See Figure R.24.[26]

[26] Electricity used to produce hydrogen is excluded from these figures to avoid double-counting, as hydrogen produced by electricity is included in the total and sectoral end-use demand figures. These shares are consistent with the sector demand charts earlier in this section.

Figure R.23:
Electricity Demand Grows Steadily in the Evolving Policies Scenario

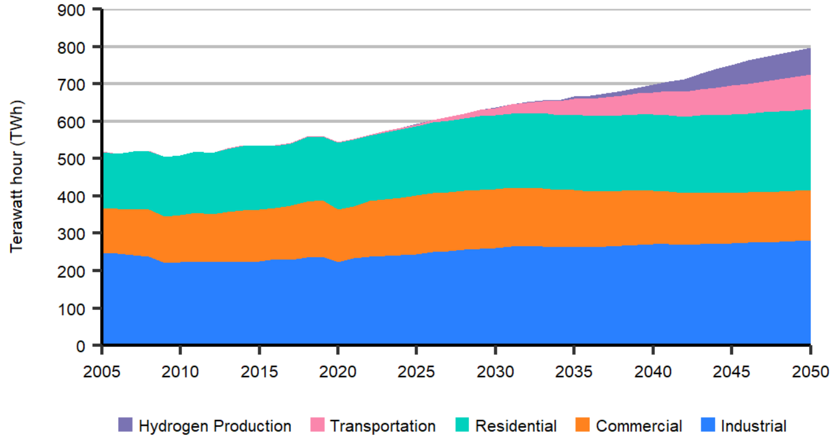


Figure R.24:
Share of Electricity in End-use Demand by Sector and Total in the Evolving Policies Scenario

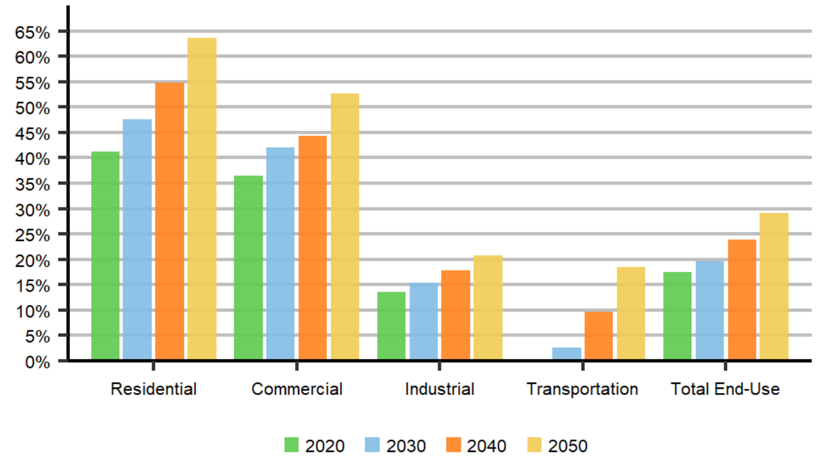


Figure R.25:
Electricity Capacity Grows Significantly in the Evolving Policies Scenario

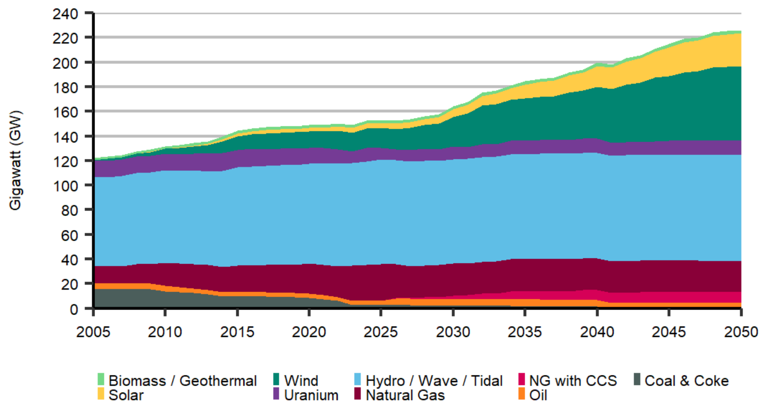
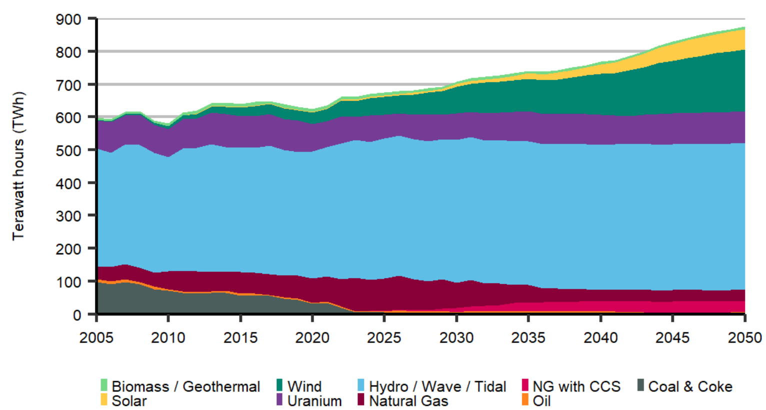


Figure R.26:
Electric Generation Trends by Primary Fuel Type in the Evolving Policies Scenario



Canada has considerable renewable resource potential including hydro, wind, biomass, and solar. Over the past decade, there have been significant changes in Canadian electricity capacity and generation trends, and it continues to evolve in the EF2021 projections. Figure R.25 shows total Canadian installed capacity by fuel type, and Figure R.26 shows electric generation by fuel type. In the earlier part of the projection, renewables and natural gas replace phased out coal generation.[27] Coal falls faster than previous projections, as recent announcements from companies suggest coal will be phased out of the Alberta electricity mix by 2023. In the longer term, falling costs lead to large growth in non-hydro renewables such as wind and solar. Nuclear generation remains relatively stable overall in the projection, with some significant year-to-year variation because of Ontario's nuclear refurbishments in the first half of the projection period. The share of low and non-emitting generation (renewables, nuclear, and fossil fuel with CCS) increases from 82% currently to 95% in 2050.[28]

Wind and solar generation also increases in the Current Policies Scenario. However, given lower carbon prices and higher wind and solar costs, wind and solar increase to a lesser degree and there is a relatively higher share of natural gas generation compared to the Evolving Policies Scenario. In 2050, natural gas makes up 16% of total generation in the Current Policies Scenario. The share of renewables and non-emitting electricity increases to 83% by 2050, compared to 95% in the Evolving Policies Scenario.

[27] Small amounts of coal with CCS generation remain to 2050, reflecting the Saskatchewan Boundary Dam project. No additional coal with CCS projects are added in the projection period based on comparative economics with natural gas with CCS and other low/non-emitting electricity.

[28] Renewable and nuclear shares refer to total electricity generation, including cogeneration.

The increase in non-hydro renewables is driven by falling costs, technological improvements, and improved integration of variable renewable energy sources such as wind and solar. Figure R.27 shows that by 2050, wind and solar capacity is added in a variety of Canadian regions. Total wind capacity rises to over 57 GW and total solar capacity rises to 26 GW. Post 2030, solar is the fastest growing renewable.

Integration of increasing wind and solar–whose generation is variable due to changing wind and sun conditions–is supported in a number of ways in the Evolving Policies Scenario. Other forms of energy, such as hydropower and natural gas, help back up these non-hydro renewables. In the Evolving Policies Scenario, energy interconnection between provinces will increase, including between Manitoba-Saskatchewan and Alberta-B.C. This adds to significant trade in Eastern and Atlantic Canada, which could increase further if projects such as the proposed Atlantic Loop increase transmission capacity. This increased ability to exchange power helps regions integrate larger amounts of variable wind and solar energy. Finally, the Evolving Policies Scenario includes around 25 GW of utility scale battery storage. This level is based on the falling costs of storage, as well as the falling costs of renewables, especially solar. Storage is particularly critical for large additions of solar.

Canada is a net exporter of electricity to the U.S., and large amounts of electricity are also traded between provinces, mainly in eastern Canada. By connecting the electricity grids of different regions, grid operators can take advantage of regional differences in electricity mixes, available variable renewable energy, and periods of peak electricity demand. Figure R.28 shows projected net exports out of Canada, as well as aggregate interprovincial trade volumes. Trade remains relatively small when compared to total generation.[29]

[29] From 2010 to 2020, annual net exports average 49 TWh, ranging between 25 and 64 TWh.

Figure R.27:

Increasing Capacity of Non-Hydro Renewables in the Evolving Policies Scenario

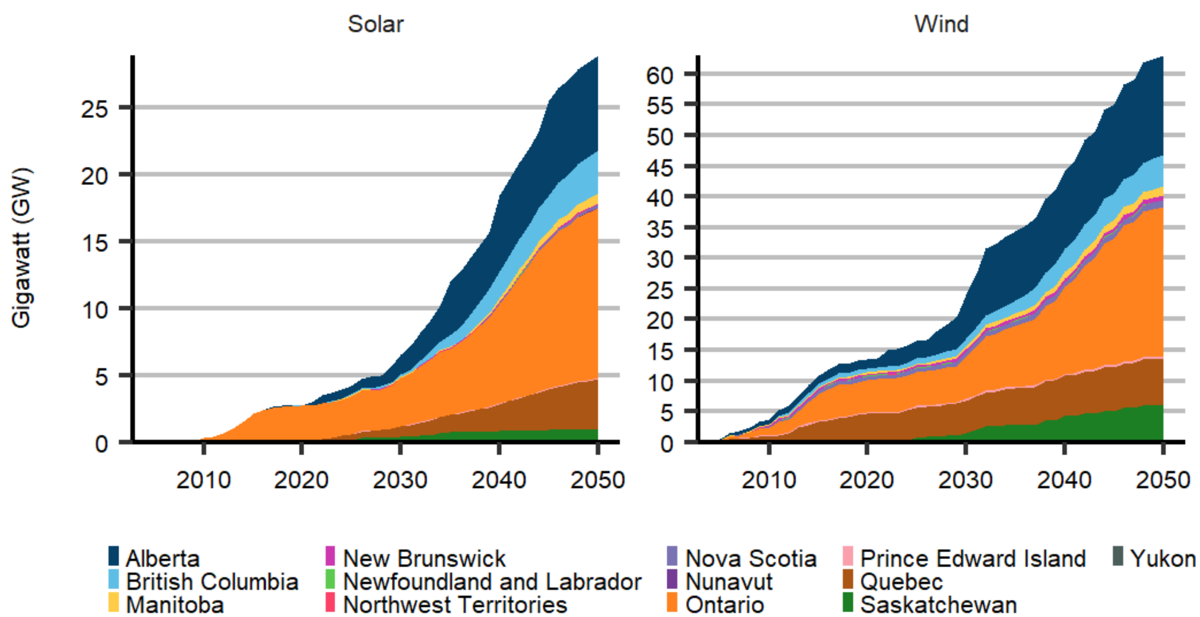
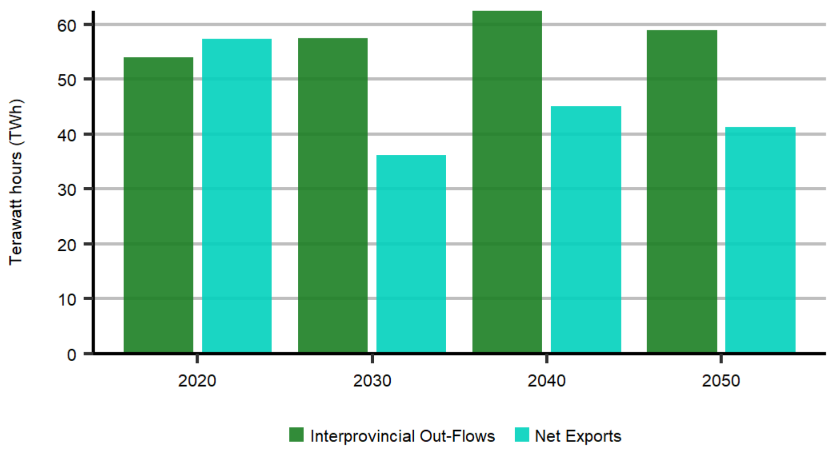


Figure R.28:
Net Exports of Electricity and Interprovincial Trade



KEY TRENDS:
Electricity Generation

- Technologies enabling Canada's transition to a low-carbon economy make inroads across the energy system, particularly in electricity generation.
- Natural gas and renewable generation is added, and most nuclear will be refurbished.
- Coal will be phased out.
- In the Evolving Policies Scenario, the share of non- and low-emitting generation increases from 82% currently, to 95% in 2050.

KEY UNCERTAINTIES:
Electricity Generation

- **Future cost declines of generating technology:** The costs associated with different generating technologies is an important factor in determining what type of facilities are built. This is especially true with rapidly changing technologies such as wind, solar, and battery storage.
- **Renewable enabling technologies:** Deployment of technologies to improve the integration of variable renewable energy, such as smart grids, storage, and transmission, could allow for greater levels of wind and solar in the projections.
- **Electricity demand growth:** This is important in determining future electricity supply. As a result, the uncertainties identified in the energy demand section are uncertainties that also apply to the electricity supply projections.
- **Export market developments:** Climate policies, fuel prices, electrification and power sector decarbonization in export markets could impact future projects and transmission developments.

Hydrogen

In recent years there has been increasing interest in low-carbon hydrogen as an important fuel in Canada and the world's transition to a low-carbon economy. Over the past few years, many countries, including Canada, have released hydrogen strategies. EF2021 is the first edition of the *Canada's Energy Future* series with a dedicated section on hydrogen supply and demand, and also introduces a hydrogen table in our online data appendix.

Our focus in this section is on hydrogen use as an energy carrier and produced by methods that emit little or no CO_2.[30] In the Current Policies Scenario, we include only currently announced projects.

In the Evolving Policies Scenario, total hydrogen demand reaches 4.7 megatonnes (MT), or 565 PJ, by 2050, as shown in Figure R.29. This accounts for 6% of total end-use energy demand. By 2050, the industrial sector accounts for 65% of hydrogen use. In this sector, hydrogen is mainly used in steel manufacturing, oil sands production, and chemical and fertilizer production. The transportation sector accounts for 25% of hydrogen demand, mostly displacing diesel in long distance freight trucking and marine transportation. The final 10% of hydrogen is used in the residential and commercial sectors, where it is blended into the natural gas stream and used for space and water heating.

Figure R.30 shows hydrogen demand by province. Hydrogen demand is the highest in Alberta, which accounts for 53% of total hydrogen demand in 2050. Alberta's relatively high demand is due to its existing industrial makeup, and its ability to produce hydrogen from natural gas with CCS, which has relatively lower costs than electrolysis earlier in the projection period. lberta's future hydrogen use is mainly in oil sands production, where it is used to replace natural gas as a source of process heat. By 2050, hydrogen demand in Alberta's industrial sector accounts for 76% of the province's total demand.

[30] Currently almost all of Canada's hydrogen is produced using a process that converts natural gas to hydrogen and CO_2, with the CO_2 being vented to the atmosphere. This hydrogen is mainly used in refineries and for fertilizer production, and is not explicitly broken out from our industrial natural gas use data.

Figure R.29:
Hydrogen Demand by Sector

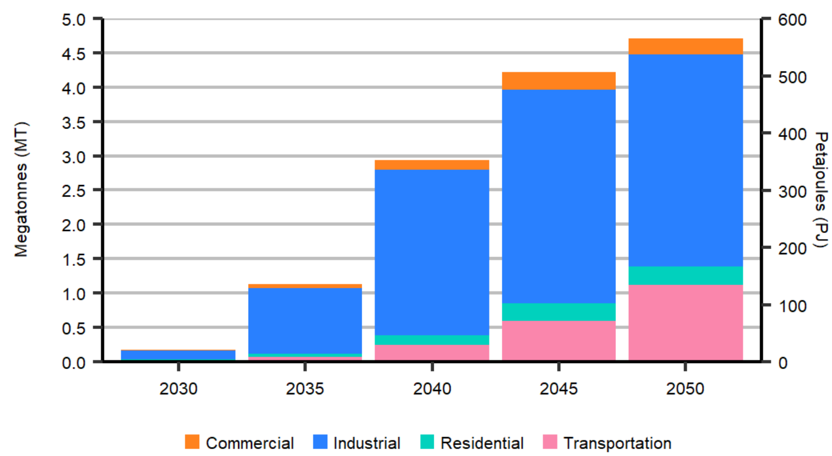
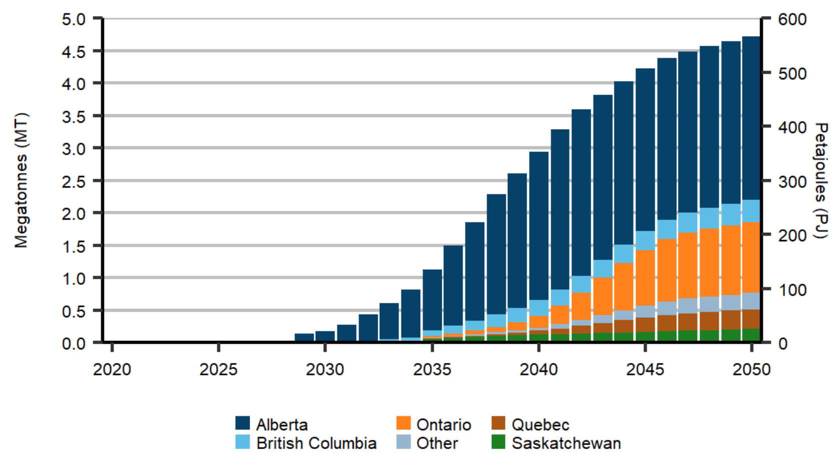


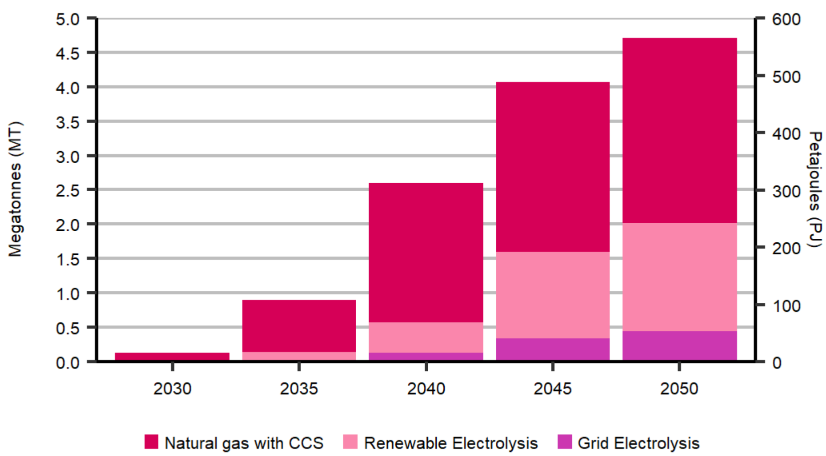
Figure R.30:
Hydrogen Demand by Region



Given that we assume hydrogen is produced to meet local demands (with no international or inter-provincial trade), hydrogen production aligns with demand. Accordingly, in the Evolving Policies Scenario, Canada produces 4.7 MT of hydrogen by 2050, matching domestic demand, and Alberta is the largest producer (with 2.5 MT of production in 2050).

In the early years of the projection, natural gas with CCS is the dominant technology for hydrogen production. Electrolysis powered by electricity from the grid and dedicated renewables becomes cost competitive towards the end of the projection. By 2050, natural gas with CCS makes up 57% of total production (Figure R.31). Production from electrolysis powered by dedicated renewables and the grid make up 33% and 9% respectively. Most regions in Canada produce hydrogen using electrolysis powered by electricity from the grid or dedicated renewables. Ontario has the highest hydrogen production from electricity, with 54% of Canada's electrolysis-based total. By 2050 close to 90 TWh of electricity is used to produce 1.8 MT of hydrogen. Similarly, natural gas with CCS uses over 422 PJ of natural gas to produce 2.69 MT of hydrogen.

Figure R.31:
Hydrogen Production by Technology



KEY UNCERTAINTIES:

Hydrogen

Infrastructure: Development of new and existing infrastructure will have an impact on the pace of hydrogen adoption in all sectors. The maximum amount of hydrogen that can be safely blended in existing infrastructure is limited to a portion of the existing pipeline capacity.

Trade: Interprovincial and international trade could alter the hydrogen supply and demand projections in this chapter. Many factors will influence the extent of trade, including whether existing transportation infrastructure is adapted to carry hydrogen, new infrastructure is built primarily for hydrogen transportation, and the evolution of costs between technologies and regions.

Future cost declines of production technology: Large scale low-carbon hydrogen production will depend on production technologies' cost decline associated with electrolyzers, CCS technology, storage, and distribution. The relative cost between various production methods will also be important, as different regions have different characteristics such as accessibility to storage, and wind and solar resource quality.

Carbon intensity: For hydrogen derived from natural gas to play a role in decarbonization, its associated emissions need to be low. Carbon capture rates greater than 90%, as assumed in this analysis, will be important. Other important areas include reducing emissions from natural gas production, including methane emissions, which are currently covered by various provincial and federal policy initiatives.

Greenhouse Gas Emissions

Currently, energy use and GHG emissions in Canada are closely related. ECCC produces Canada's official emission projections for the United Nations Framework Convention on Climate Change.[31]

The majority of GHGs emitted in Canada are a result of fossil fuel combustion. Fossil fuels provide much of the energy used to heat homes and businesses, transport goods and people, and power industrial equipment. Energy related emissions accounted for 82% of Canadian GHG emissions in 2018.[32] The remaining emissions are from non-energy sources such as agricultural and industrial processes and waste handling.

[31] Data sets are also available through the Government of Canada's Open Government portal.

[32] As defined in ECCC's national inventory report, energy related emissions includes stationary combustion sources, transportation, fugitive sources, and CO_2 transport and storage.

KEY TRENDS:

Fossil Fuel Use and GHG Emissions

- Overall unabated fossil fuel use declines in the Evolving Policies Scenario.
- Natural gas, oil, and coal each have their own distinct future trend, but use of all three falls over the long-term.
- The emission intensity of fossil fuel use falls, driven by the phase out of coal and the long-term adoption of CCS.

Does the Evolving Policies Scenario Meet Canada's Climate Commitments?

The Evolving Policies Scenario provides an energy supply and demand outlook for Canada under the general premise that global and domestic climate action continues to increase at its recent pace. EF2021 focuses on potential future outcomes for Canada's energy system. It should not be viewed as an assessment, or a pathway, for meeting Canada's climate commitments.

ECCC produces the official analysis of Canada's current emissions outlook and performance against its climate commitments. Recent ECCC projections included in Canada's updated Nationally Determined Contribution (NDC)[33] show that with the latest measures in the Strengthened Climate Plan and Budget 2021, a GHG emission reduction of 36% below 2005 levels by 2030 is achieved. This reduction exceeds Canada's original NDC pledge of 30% below 2005 levels, but additional measures could be needed to hit the updated NDC of 40-45% below 2005 levels.

The unabated fossil fuel demand trends in the Evolving Policies Scenario, as shown in this section, imply significant reduction in GHG emissions. They also imply that the Evolving Policies Scenario is unlikely to achieve net-zero emissions by 2050. Recognizing this fact, we have included the "Towards Net-Zero" section in EF2021.

[33] Submitted to the UNFCCC as part of the Paris agreement.

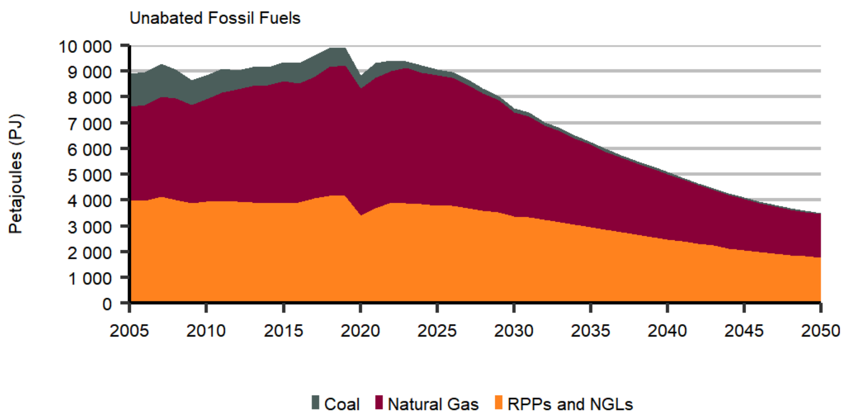
Figure R.32 breaks out total primary demand into unabated fossil fuel demand, which will make up the majority of Canadian GHG emissions, and low emission sources, which include renewable, nuclear, fossil fuels with CCS, and fossil fuels for non-combustion purposes.[34] Relative to 2020 levels, unabated fossil fuel consumption is 19% lower in 2030, 45% lower in 2040, and 62% lower in 2050. Meanwhile, low-emission energy rises, and accounts for 67% of energy use in 2050, compared to just 31% in 2021.

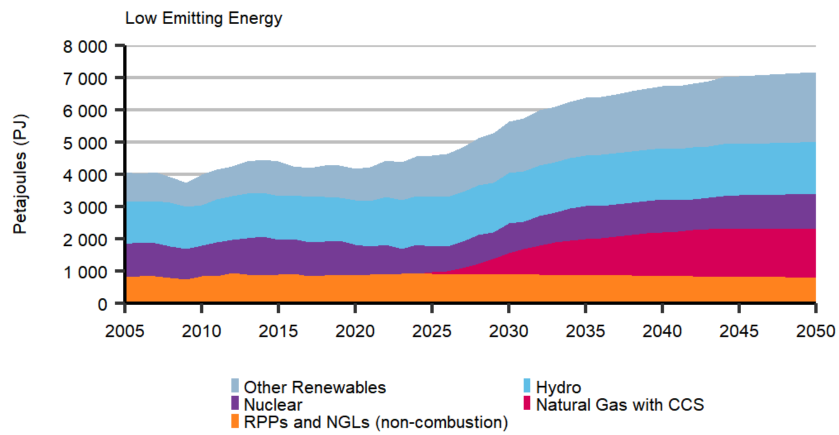
Trends vary among fossil fuels. Coal consumption significantly declines over the projection, driven by its phase-out from electricity generation by 2030.[35] Use of RPPs, such as gasoline and diesel, gradually declines throughout the projection period. In the earlier years, this decline is driven by efficiency improvements and increased blending of biofuels, and in the long term is driven by increased electrification of the transportation sector. Use of natural gas continues to grow in the very early part of the projection period, following its increased role in power generation and its use in rising oil sands production. In the longer term, its overall use falls but its use with CCS increases significantly for industrial and power generation use and low-carbon hydrogen production.

[34] Examples of fossil fuels for non-combustion purposes include petrochemical feedstocks, asphalt and lubricants. We include these non-energy demands along with energy use because they are derived from energy commodities such as crude oil and NGLs, and form part of Canada's energy balances.

[35] Small amounts of coal with CCS generation remain to 2050, reflecting the Saskatchewan Boundary Dam project. No additional coal with CCS projects are added in the projection period based on comparative economics with natural gas with CCS and other low/non-emitting electricity.

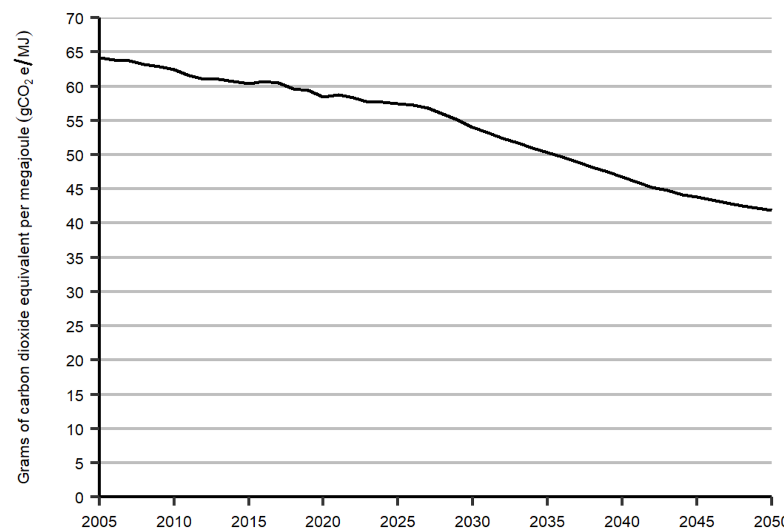
Figure R.32:
Total Primary Demand by Type





Changing proportions of which fossil fuels are consumed leads to declining combustion-related GHG emissions per unit of fossil fuel energy used in the Evolving Policies Scenario, particularly with coal use declining to 2030. Deployment of CCS technology in industrial facilities also reduces the GHG intensity of fossil fuel use in the longer term. As shown in Figure R.33, fossil fuel emission intensity in 2030 is 9% lower than 2019, and 16% lower than 2005 in the Evolving Policies Scenario. By 2050 it is 29% lower than 2019, and 35% lower than 2005 in the Evolving Policies Scenario. This decline drives emission reductions when combined with falling fossil fuel use, as 2030 total fossil fuel use is 16% lower than 2019, and 6% lower than 2005. By 2050, total fossil fuel use is 46% lower than 2019, and 40% lower than 2005. Accounting for reductions in non-combustion emissions, such as reducing methane emissions, as well as including emission credits purchased through international trading mechanisms (like Quebec's emission trading with California), could further decrease emission intensity.

Figure R.33:
Fossil Fuel Emission Intensity Falls due to Higher Shares of Natural Gas, Less Coal, and Greater Adoption of CCS in the Evolving Policies Scenario



Could Carbon Removals Bring Canada to Net-Zero in the Evolving Policies Scenario?

Global and domestic net-zero pathway exercises rely on some degree of carbon removal or negative emission technology to reach net-zero by 2050. The degree varies depending on the scenario and underlying assumptions. For example, the Net-Zero Emissions by 2050 Scenario in the IEA's Net-Zero by 2050 report includes about 1.9 gigatonnes of CO_2 that is removed by negative emissions technologies in 2050. In the Canadian context, the Canadian Institute for Climate Choices' Canada's Net Zero Future report shows availability of engineered negative emission technologies, particularly direct air capture, and accounts for 0 to 425 MT of CO_2 emission reductions in 2050 across the 62 scenarios they analyzed. However, the Canadian Institute for Climate Choices recognizes potential challenges, both technical and economic, and identifies ways to reach net-zero in the absence of negative emissions technologies.

Negative emissions technologies and enhanced biological sinks involve removing CO_2 from both the emissions' source and the atmosphere, and storing it in land, ocean, or geological reservoirs.[36] While hypothetically promising, most assessments agree that negative emissions technologies are not a replacement for conventional mitigation and adaptation methods, due to high costs, potential risks, and uncertainties involved.[37]

Notable GHG removal methods include:

Reforestation and afforestation[38]: Carbon can be sequestered in biomass through restocking of existing forests and woodlands that have been depleted, or introducing trees to areas that have not previously been forested.

Soil carbon sequestration[39]: Carbon can be removed from the atmosphere and stored in the soil carbon pool, primarily in the form of soil organic carbon. This can be accomplished through a variety of methods, including the restoration of degraded soils or widespread adoption of soil conservation practices in agriculture. For instance, reducing soil carbon loss can be achieved in certain circumstances by switching from tillage to no-till cropping.

Bioenergy with carbon capture and storage (BECCS)[40]: Carbon can be captured and stored by geological sequestration or land application, as energy is extracted from biomass through combustion, fermentation, or other conversion methods. Limiting factors for BECCS include the availability and sustainability of feedstock biomass, and the availability of carbon storage capacity.

Direct air capture: Carbon can be captured from the atmosphere to produce a concentrated stream of CO_2. It can then be sequestered (resulting in emission removals), or used to make carbon-neutral synthetic fuels. Direct air capture uses a lot of energy, so large scale deployment could impact energy supply and demand trends.

The Evolving Policies Scenario shows a 60% drop in unabated fossil fuel use by 2050, which would result in a significant reduction in emissions. The Evolving Policies Scenario does not include assumptions related to deployment of large-scale carbon removals. Whether the Evolving Policies Scenario could be net-zero with deployment of carbon removals depends on two key considerations:

1. Although unabated fossil fuel use falls, it is still a significant part of the energy mix, and implies significant levels of emissions. This would require a large deployment of carbon removal technology. The feasibility of this deployment would depend on many factors, including cost reductions of emerging technologies such as direct air capture, and the availability and costs of BECCS and nature-based solutions. Given these are emerging solutions, large deployment is highly uncertain.

2. Deployment of large-scale carbon removals would likely change the Evolving Policies Scenario projections. For example, large scale direct air capture deployment would involve a significant increase in natural gas and/or electricity use. Likewise, a large deployment of BECCS could change the Evolving Policies Scenario electricity projections.

Given the uncertainty with removal technologies, especially at large scales, and the fact that large scale removals would affect the projections, the Evolving Policies Scenario as described in this section should not be considered a net-zero pathway.

[36] IPCC AR5 – Assessing Transformation Pathways.

[37] IPCC AR5 – Assessing Transformation Pathways.

[38] IPCC AR5 – Agriculture, Forestry and Other Land Use.

[39] IPCC AR5 – Agriculture, Forestry and Other Land Use.

[40] For a review of BECCS and direct air capture research, see section 6.9 of IPCC AR5 - Assessing Transformation Pathways.

Towards Net-Zero

Electricity Scenarios

A key objective of the 2015 Paris Agreement is to hold the increase in the global average temperature to well below 2 degrees Celsius and pursuing efforts to limit the temperature increase to 1.5 degrees above pre-industrial levels. Scientific assessments have shown that limiting the temperature increase at those levels requires deep GHG emission reductions, with a key milestone being achieving net-zero emissions or carbon neutrality by 2050.[41] As of August 2021, about 130 countries, including Canada, have set or are considering net-zero by 2050 emissions targets.[42] Canada has set targets to reduce the country's GHG emissions by 40-45% below 2005 levels by 2030 and to achieve net-zero GHG emissions by 2050.

Over 82% of Canada's GHG emissions are from energy producing and consuming processes. To achieve net-zero emissions by 2050, transformational changes are required to the way Canadians produce and consume energy. The pathway to achieving net-zero will likely require a greater level of change than we model in EF2021 or previous reports in the *Canada's Energy Future* series.

In this section, we introduce six new scenarios that explore net-zero pathways for Canada's electricity sector. This analysis is an important step in modeling related to a net-zero energy system in *Canada's Energy Future* series.

41 For example, the IPCC Special Report on Global Warming of 1.5 °C (SR15) finds that limiting global warming to 1.5°C would reducing anthropogenic emissions of CO_2 by about 45 percent from 2010 levels by 2030, reaching 'net zero' around 2050.

42 Based on data reported by the Energy and Climate Intelligence Unit.

Why the Electricity Sector?

In this analysis, we focus on the electricity sector, recognizing the pivotal role of electricity in the pathway to net-zero. Many climate modeling and energy system assessment studies have shown that an electricity sector with net-zero or net-negative emissions, and an increasing share of electricity in the end-use fuel mix, is a cornerstone of an energy system in a carbon neutral world. For example, the *IPCC Special Report on Global Warming of 1.5 °C* shows that pathways that would limit global warming below 1.5 °C include a rapid decline in the carbon intensity of electricity and an increase in electrification of energy end-use.

There are some unique aspects of electricity that make it an important part of most deep decarbonization pathways. Mature and commercially ready technologies exist for decarbonizing electricity. The costs of many low or zero GHG emission generation technologies have declined over the past decade, making them attractive for electric utility investors. Electricity is also a highly versatile form of energy. Converting electricity into end-use energy services can be done at high efficiencies and without any emissions at the point of consumption.

One major challenge for economy-wide deep decarbonization is the distributed nature of GHG emissions. For example, millions of vehicles emit GHGs when fossil fuels are combusted to move the vehicles around. Similarly, millions of buildings combust fossil fuels for space heating, emitting a significant amount of GHGs. When energy end-uses are electrified, no GHGs are emitted at the point of consumption. When energy end-uses are electrified in a decarbonized electricity sector (i.e. where the electricity is generated with low or zero GHG emissions), economy-wide deeper GHG reductions can be component of climate action.

In pursuit of net-zero emissions, the electricity sector in Canada has an early advantage. About 82% of Canada's electricity already comes from non-GHG emitting sources such as hydro, nuclear power, wind, and solar. This share has been growing, and emissions associated with the remaining generation have declined significantly over the past two decades. The GHG emissions intensity of Canada's electricity generation has declined by 45% from 220 grams CO_2 equivalent (gCO_2e)/kWh in 2005 to 120 gCO_2e/kWh in 2019.[43]

The critical role of Canada's electricity sector in achieving net-zero emissions has received the attention of policy makers across Canadian jurisdictions. As outlined in the Policy Appendix, many programs and policies have been implemented by the federal, provincial, and territorial governments of Canada to reduce GHG emissions from the electricity sector and to promote electrification of end-use energy. For example, Canada's strengthened climate plan, A Healthy Environment and a Healthy Economy, commits about $4 billion of investment to expand the supply of cleaner electricity, modernize Canada's electricity systems, and make electrification of energy end-uses affordable.

43 Obtained from National Inventory Report 1990 – 2019: Greenhouse Gas Sources and Sinks in Canada.

What is "Net-Zero"?

"Net-zero" GHG emissions refers to the concept of balancing human-caused GHG emissions with removals from the atmosphere. This includes non-energy emissions from land use, agriculture, and industrial production, in addition to emissions from the energy system. Reaching net-zero emissions does not necessarily require eliminating all emissions everywhere. Instead, residual emissions can be balanced by enhancing biological sinks and using negative emission technologies. What the exact balance might be between removing and emitting GHGs into the atmosphere is uncertain. However, it is clear that Canada's likelihood of achieving our net-zero target increases as our energy system emissions fall.

See the Towards Net-Zero section in our Energy Futures 2020 report for a discussion of what "Net-Zero" means, and what achieving net-zero GHG emissions could mean for Canada's energy system.

Methods and Assumptions

The basis for our modelling of Canada's electricity sector in a net-zero world begins with the electricity production and consumption results of the Evolving Policies Scenario. We build on those results in three main ways:

1. We dive deeper into the electric power sector by applying an electric power system planning and operations simulation model. It selects and operates the optimal set of power generation technologies that minimize the total cost while satisfying future power demand.

2. For each province, we assume a specific higher electricity demand level than the Evolving Policies Scenario to capture an increased level of energy end-use electrification consistent with expectations of a net-zero future.

3. We assume more stringent climate action in the form of a higher carbon price than the Evolving Policies Scenario. The expected result is that a sufficiently high carbon price will drive the electricity sector towards net-zero emissions.

Given the uncertainty around the costs and viability of different low-carbon technologies, there are many potential pathways to achieve a net-zero electricity system. For this reason, the analysis is developed around six scenarios that explore some of the key uncertainties. Across scenarios we change key inputs such as demand, carbon prices, and technology availability. The main scenario we developed for this part of the analysis is called Net Zero Electricity (NZE) Base scenario. The premise and main characteristics of the NZE Base and other alternative scenarios are presented in Table NZ.1.

Table NZ.1:
Premise and Characterizing Features of Net-Zero Electricity Scenarios

Scenario	Scenario Rationale	Allowable Capacity Expansions	Other Features
NZE Base	Continually increasing Canadian climate policies may lead to a higher carbon price and a higher level of end-use energy demand electrification than the assumptions made in the Evolving Policies scenario.	Generation technologies: natural gas fired combined cycle, natural gas fired simple cycle, and natural gas fired combined cycle with CCS* units, wind, solar, hydro, conventional nuclear, and SMR. Electricity storage. Inter-provincial transmission.	Electricity demand is 10-30% higher than the Evolving Policies Scenario, depending on the province. Carbon pricing is higher than the Evolving Policies Scenario, reaching \$2020 300/tonnes CO_2 by 2050.
Higher Carbon Price	It is plausible that more aggressive climate action is needed to drive the energy systems towards net-zero, leading to a higher carbon price than the value assumed in the NZE Base scenario.	Same as NZE Base.	Same electricity demand as Base. **Carbon pricing reaches \$2020 800/tCO_2 by 2050.**
Higher Demand	A higher level of electrification is possible due to uncertainty around specific climate action and technology development.	Same as NZE Base.	**Electricity demand is 15-45% higher than the Evolving Policies Scenario, depending on the province.** Same carbon pricing as NZE Base.
Limited Transmission	Interprovincial transmission expansion is costly, and the timing of investments is uncertain. Therefore, new interprovincial transmission development may not be feasible.	Same as NZE Base, but **no new inter-provincial transmission is allowed.**	Same electricity demand and carbon pricing as NZE Base.
Hydrogen	There is a high level of interest in hydrogen as a technology path to decarbonize the economy. Accordingly, there is the possibility of low-cost low/zero carbon hydrogen being available for electricity generation.	All NZE Base options and **hydrogen fired generation technologies.**	Same electricity demand and carbon pricing as NZE Base.
BECCS	Negative emissions technologies feature prominently in previous net-zero scenarios. Within that scope, biomass-fired electricity generation with CCS is attractive as it simultaneously produces electricity and removes carbon dioxide from the atmosphere. Therefore, it is plausible that biomass-fired electricity generation with CCS is available in the near future.	All NZE Base options and **biomass CCS* generation technology.**	Same electricity demand and carbon pricing as NZE Base.

* CCS technologies including natural gas with CCS and BECCS are only allowed to be built in Alberta and Saskatchewan due to the greater availability of proven geological potential to store CO_2 and availability of active CCS projects in these provinces.

A core set of assumptions including technology costs, fuel prices, and hourly demand profile shapes were held constant across scenarios. Assumed capital costs of generation and storage technologies are listed in Table NZ.2.

Table NZ.2:
Assumed Technology Capital Costs ($2020 CDN/kW) by Investment Year

Technology	Aggregated Group	Capital Cost in Investment Year		
		2030	2040	2050
Natural Gas Simple Cycle	Natural Gas	950	950	950
Natural Gas Combined Cycle	Natural Gas	1 300	1 300	1 300
Natural Gas Combined Cycle with CCS	Natural Gas CCS	3 000	2 500	2 000
Solar	Solar	972	604	376
Wind	Wind	1 115	868	676
Hydropower	Hydro	4 000	4 000	4 000
Nuclear	Nuclear	7 000	7 000	7 000
Small Modular Reactor	Nuclear	7 000	6 000	5 000
Hydrogen Simple Cycle	Hydrogen	1 625	1 560	1 430
Hydrogen Combined Cycle	Hydrogen	1 813	1 813	1 813
Biomass with CCS	Biomass CCS	4 752	4 512	4 299
Battery Electricity Storage (4 h storage duration)	Storage	425	275	190

Notes
Where applicable, capital cost reduction due to technology development and learning is considered.
In results figures, some generation technologies are aggregated into a group as indicated in the column "Aggregated Group."

Other simplifying assumptions in the net zero electricity analysis:

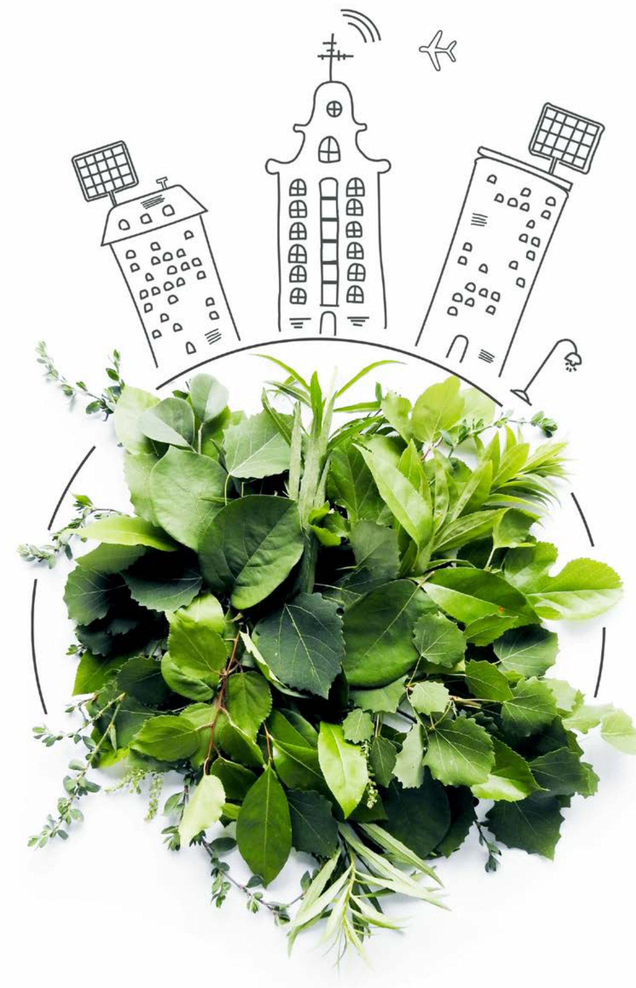
- The analysis is limited to the ten provinces. Electricity systems of the three territories are excluded from the analysis.
- A few other low carbon generation technologies that have attracted recent interest, including geothermal, tidal, conventional biomass, and offshore wind are excluded.
- Electricity storage is limited to battery electric storage with four-hour storage capacity.
- Demand-side management and distributed electricity resources are excluded.
- Only grid-connected generation is modelled.
- Electricity trade with the U.S. is not modelled.

This analysis is based on the hourly electricity module of the Energy Futures Modeling System (see Appendix 2). It optimizes the capacity investments and operations of the provincial electricity systems at one-hour intervals. Interprovincial electricity trade is also modelled. The main objective of the model is to construct and operate an optimal generating unit fleet that would minimize the total cost of satisfying electricity demand in Canada under the particular scenario assumptions. We complete this analysis for the period 2030-2050. Here we present the results for 2030 and 2050, the two years for which Canada has set major emission reduction targets.

Approach to Electricity Sector Emissions in this Net Zero Electricity Analysis

The net-zero electricity scenarios described in this section are intended to explore how Canada's electricity system might evolve in the broader context of Canada moving towards net-zero for the entire energy system. In an economy-wide net-zero transition, it is possible that some specific sectors could continue to emit GHGs, which would have to be offset by emission removals in other sectors at a given price.

Therefore, in our analysis, we do not force the electricity sector to be purely non-emitting in any year. Rather, we use the assumed carbon price, which serves as a proxy for the cost of carbon removal, as well as potential technology options to determine the ultimate carbon emissions of the sector. Our emission intensity results show that if bioenergy with CCS is available, the electricity sector could be negative emitting. Other scenarios show a dramatic reduction in grid emission intensity compared to current levels, but achieving net-zero could require moderate levels of offsets from carbon removal options such as nature-based solutions or direct air capture.



Results

NZE Base Scenario Electricity Supply

We first discuss the results for the NZE Base scenario and visit the other scenario results later in the section. Figure NZ.1 shows the installed electricity generation capacity mix in Canada by technology in the NZE Base scenario.

In the NZE Base scenario, non-emitting generation technologies (i.e., hydro, nuclear, solar, and wind) and electricity storage account for 80% of the installed generation capacity in 2030. By 2050, that share increases to 89%. Additionally, low-emitting natural gas CCS units are built in Alberta and Saskatchewan. Our results see an addition of about 5.6 GW of natural gas CCS units by 2050. Natural gas CCS account for about 2% of all provincial capacity and 8% of capacity in Alberta and Saskatchewan.

At a combined capacity of 134 GW, which is about 41% of the installed capacity, solar and wind dominate the electricity generation fleet in 2050. Wind capacity doubles from 2019 levels by 2030, and is five times greater by 2050. Solar capacity is twenty times larger compared to 2019 levels by 2050. Electricity storage is installed to facilitate the operations of variable renewables and support grid operations. At an average annual growth rate of about 1.7 GW/year, storage sees a rapid growth throughout the analysis period. From 2019 capacity of about 0.01 GW, storage capacity reaches 52 GW by 2050.

New hydropower capacity additions are relatively small and only see a cumulative new capacity addition of about 4.2 GW in the period 2030 to 2050, a 5% increase from 2019. Similarly, the growth of nuclear power is also comparatively small. All new nuclear additions are through small modular reactor (SMR) technology. About 6.6 GW of SMR units are added by 2050. Based on our cost assumptions, no new nuclear capacity is added until 2040. In combination, hydropower and nuclear represent 5% of new capacity additions. Despite the lower share of new capacity additions, as discussed later in this section, hydropower and nuclear power play an important role in supporting Canada's electricity supply on the path towards net-zero.

Fossil fuel-based technologies, mainly natural gas units, represent approximately 20% of total generating capacity in 2030 and decline to 11% by 2050. Natural gas unit additions are dominated by simple cycle gas turbines and primarily provide grid balancing.

Figure NZ.2 shows electricity generation by technology in the NZE Base scenario. In general, the electricity system must constantly balance electricity generation with electricity use. Electricity use varies with minute-to-minute changes in demand by homes, businesses, and industry. Electricity generation then must vary to match this demand. Some generation types are flexible and can be altered by system operators to meet demand. Other resources are less flexible, and others, such as wind and solar, are not flexible and instead vary based on wind or sunlight availability. Our model takes these factors into account and chooses the optimal generation mix based on level of demand, relative costs, and resource constraints.

Figure NZ.1

Installed Electricity Generation Capacity in Canada in the NZE Base Scenario

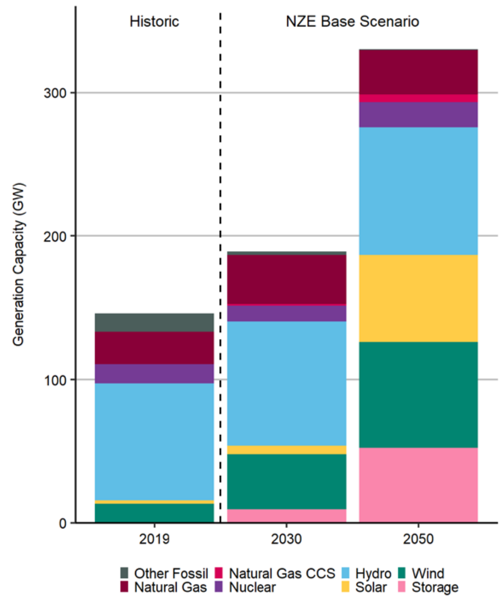


Figure NZ.2

Electricity Generation in Canada by Technology in the NZE Base Scenario

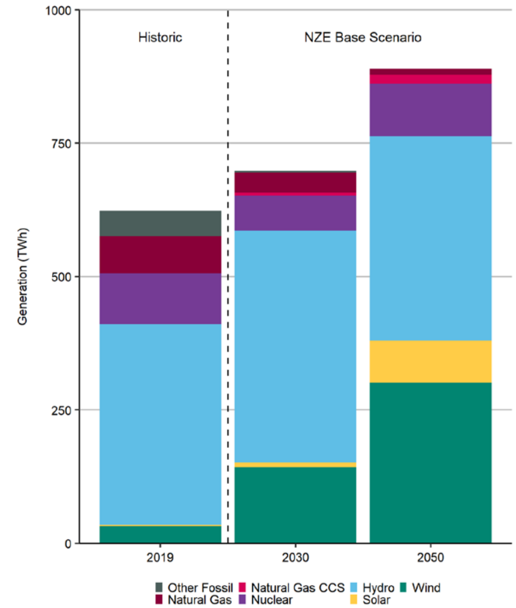


Figure NZ.2 Notes: Since storage is not a primary generator of the electricity it stores and ultimately dispatches, it is not included in this figure. By 2050, storage is primarily used to store electricity produced by wind and solar in low demand periods, for use in high demand periods. About 7.5% of the electricity produced in 2050 by solar and wind is first stored in storage units and later delivered to the consumers.

KEY TRENDS:

Electricity Supply in the NZE Base Scenario

- Wind and solar dominate new capacity additions. These two technologies account for 59% of new capacity additions through 2050.
- Electricity storage sees a rapid growth and reaches 15% of total installed capacity in 2050.
- New demand growth is primarily satisfied by wind and solar with other low carbon technologies such as SMR, hydropower, and natural gas CCS providing supplemental energy.
- All new nuclear additions are SMR units, which begin to make inroads after 2040.
- Natural gas CCS plays an important role but is restricted to the provinces with greater carbon storage potential.
- Almost all conventional fossil fuel-fired electricity supply comes from natural gas simple cycle units.
- The importance of hydropower remains high. However, there are not major hydropower capacity additions due to relatively high assumed capital costs.

In the NZE Base Scenario, non-emitting generation (e.g., hydro, nuclear, solar, and wind) produces 93% of electricity in 2030, and 97% in 2050. Overall, by 2030, 94% of electricity is generated by low- and non-emitting technologies (renewables, nuclear, and CCS-enabled fossil fuel), rising to 99% in 2050. Hydropower and nuclear power provide the largest share of the electricity supply in both periods. However, the amount of electricity provided by those two technologies remains relatively unchanged from 2019 levels, at roughly 50 TWh throughout the projection period. New demand growth is primarily satisfied by wind and solar, with electricity storage systems and to a lesser degree, simple cycle gas turbines, ensuring system reliability.

The current share of fossil fuel-based electricity generation is 19%, and this decreases over the projection period. By 2050, the total share of electricity produced by natural gas-fired generation reaches 3% of the total electricity supply. About two-thirds of that comes from natural gas units equipped with CCS technology. The remainder consists of natural gas simple cycle units that provide some grid balancing services to maintain system reliability.

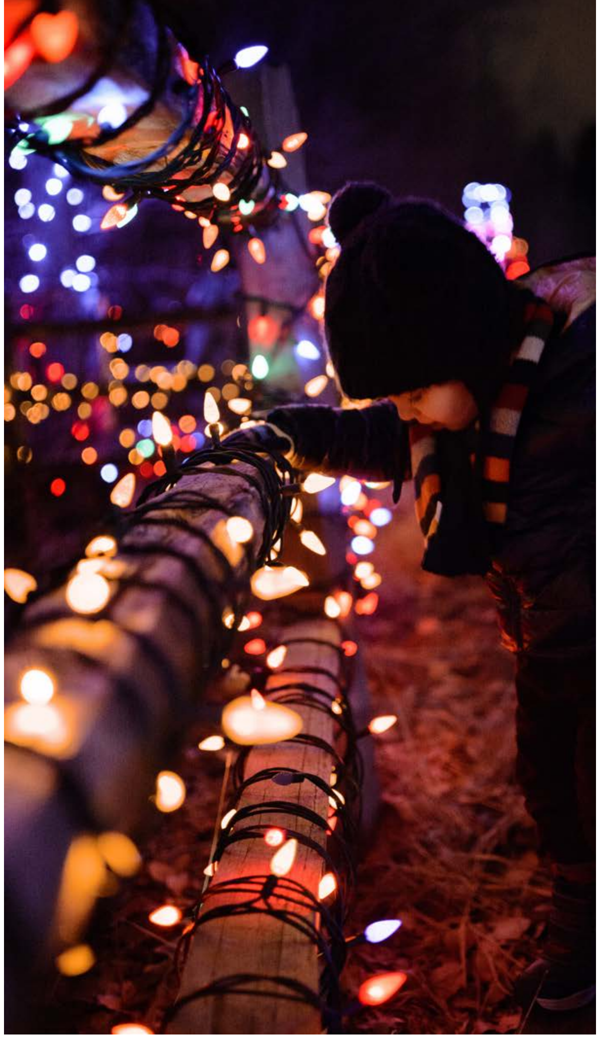
Storage systems do not produce electricity but rather store electricity produced by other generating units for later delivery to consumers. This is a critical service needed to operate electricity systems with larger shares of variable generating sources such as solar and wind. Our results show that storage is primarily used to move electricity produced by wind and solar in low demand periods to high demand periods. We find that about 7.5% of the electricity produced by solar and wind is first stored in storage units and later delivered to the consumers.

Canada has a diverse energy system. Figure NZ.3 shows the generation mix for each province in the NZE Base scenario. We find that electricity generation in B.C., Manitoba, Quebec, and Newfoundland and Labrador continues to see the supply dominated by hydropower. In the three former provinces, however, new demand is satisfied by wind and solar. Nuclear power[44] is limited to Ontario and New Brunswick and represents about 41% and 24%, respectively of the provincial electricity supply in 2050.

[44] Nuclear power includes the electricity produced by both legacy units and new SMR units.

Natural gas-fired electricity generation remains a relatively important share, about 12% and 15%, respectively of the electricity supply of Alberta and Saskatchewan in the NZE Base scenario in 2050. However, by 2050, about 80% of the natural gas-fired generation in these two provinces is from natural gas CCS units.

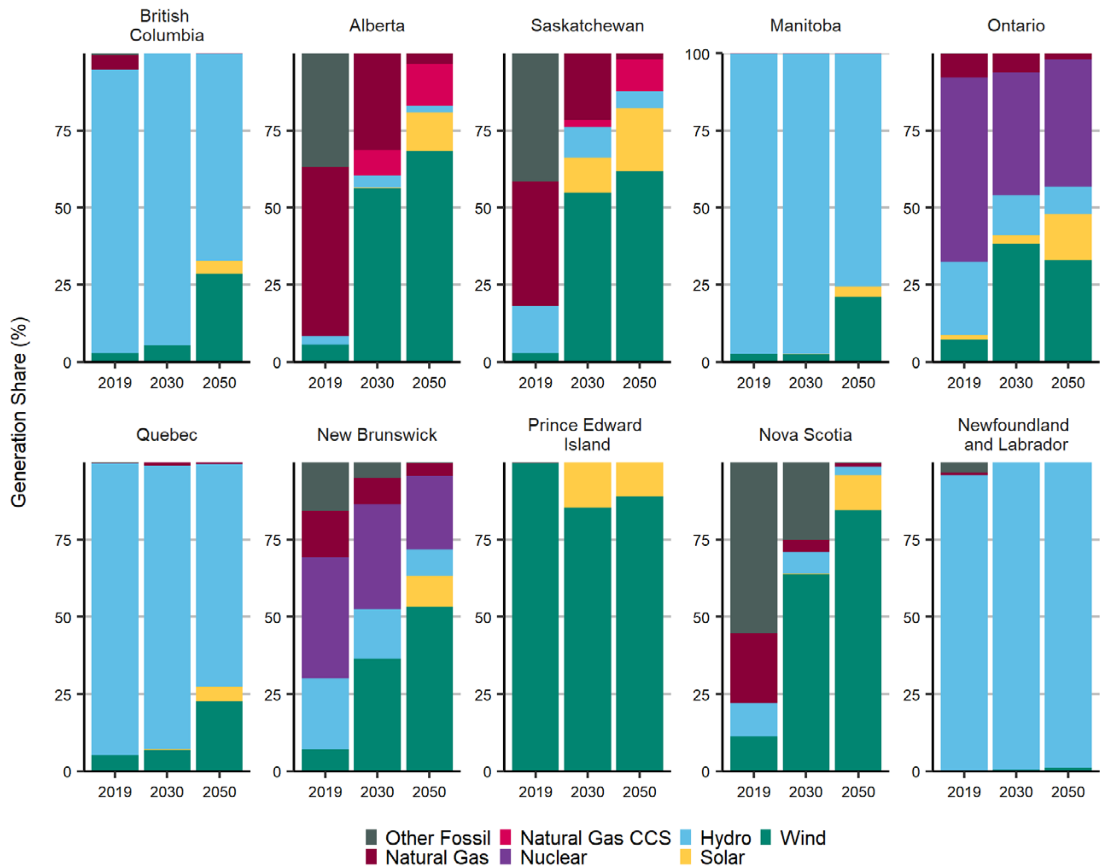
In the NZE Base scenario, inter-provincial electricity transmission capacity expansions increase, mostly among the four western provinces. The combined electricity transfer capacity of the three western inter-provincial electricity corridors (i.e., B.C.–Alberta, Alberta–Saskatchewan, Saskatchewan–Manitoba) almost triples in the NZE Base scenario. Outside of the western region, only the New Brunswick–Prince Edward Island inter-provincial corridor sees transmission expansion at about 30% growth compared to current levels.[45]



[45] Other assessments have suggested that inter-provincial transmission expansion among eastern Canadian provinces, particularly among the Atlantic provinces, would facilitate the electricity system decarbonization efforts. Our analysis does not capture that under the assumptions we make, with a potential factor being our simplifying exclusion of electricity trade with the U.S.

Figure NZ.3

Share of Electricity Generation by Technology in Canadian Provinces in the NZE Base Scenario



As noted above, in the NZE Base scenario the share of electricity supplied by technologies with zero carbon intensities increases to about 97%, while another 2% is from low-emission natural gas CCS units. This is driven by two main factors. First, the capital cost of wind, solar, and electricity storage declines significantly in this scenario, thereby reducing their average cost of production. Second, the increasing carbon price leads to higher generation costs for fossil fuel-fired generating units, making them less competitive against other options.

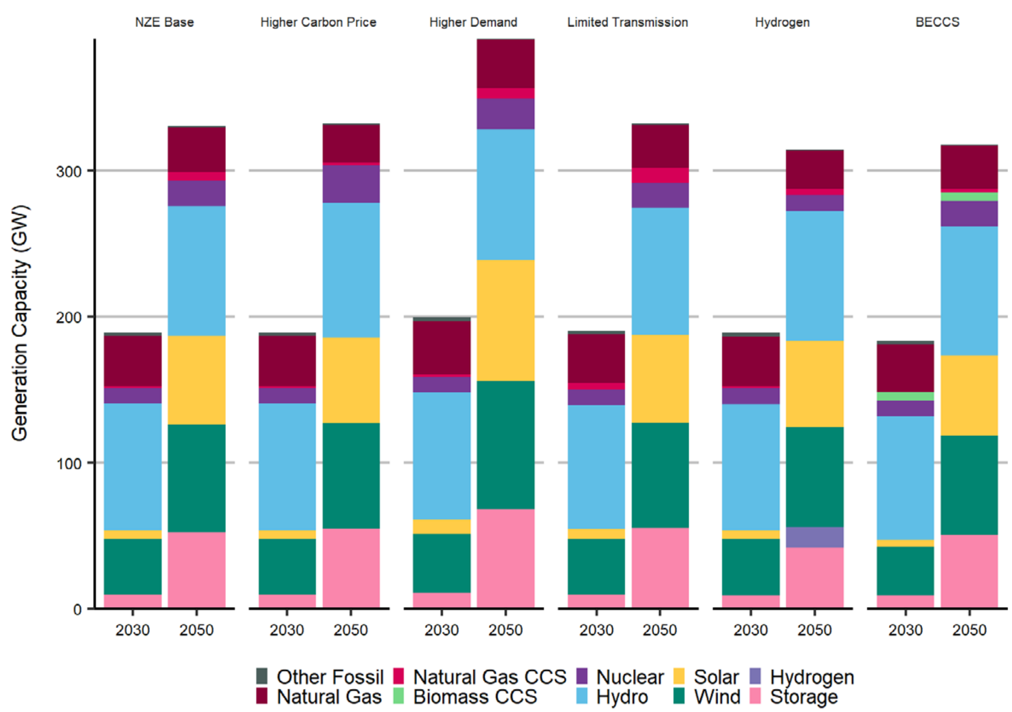
Similar results were observed in other scenarios, but some noteworthy observations are discussed below.

Electricity Supply in Alternative Scenarios

In this section, we compare the results in other electricity scenarios with the NZE Base scenario. All alternative scenarios see a nearly identical level of inter-provincial transmission expansion as the NZE Base scenario. The exception is the Limited Transmission scenario, where no additional transmission expansions are allowed. Furthermore, similar to the NZE Base scenario, most of the new demand is satisfied by wind and solar, while high GHG emission generation technologies see rapid decline.

Figure NZ.4 shows installed capacity by technology in different scenarios. Figure NZ.5 shows the cumulative new capacity additions by technology type by 2050 in different scenarios. Figure NZ.6 shows the amount of electricity generation.

Figure NZ.4:
Installed Capacity by Technology in Different Scenarios



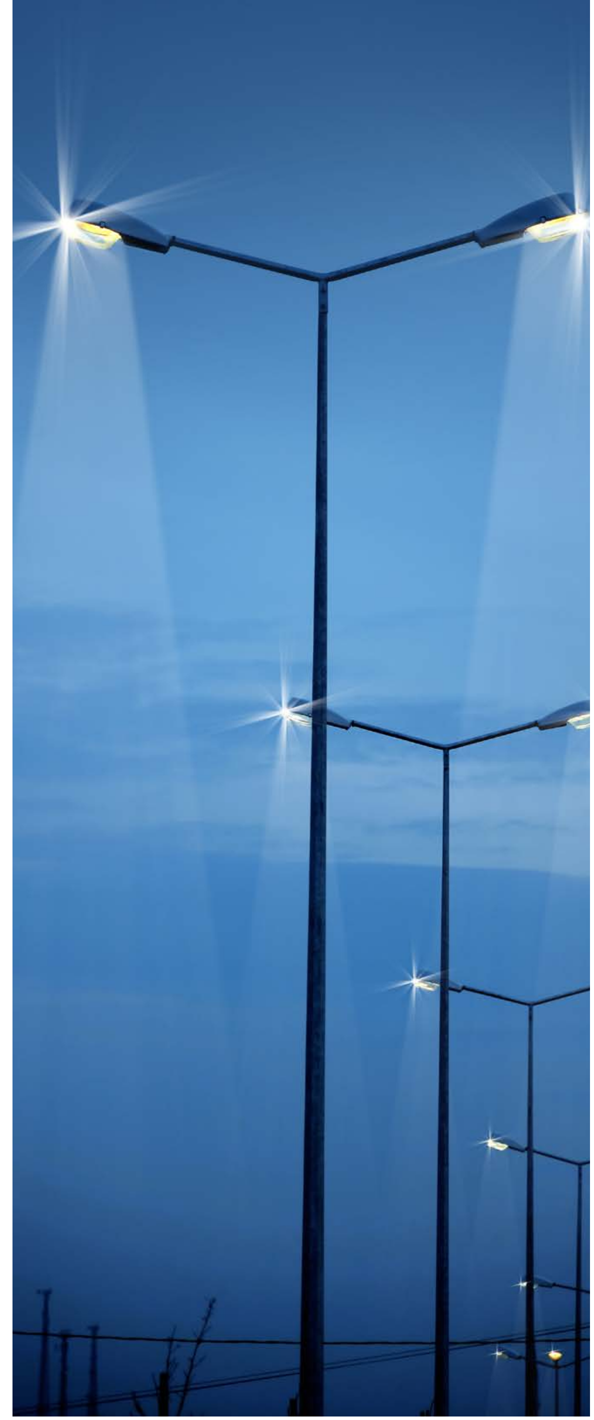


Figure NZ.5:
Cumulative New Capacity Additions by 2050 in Different Scenarios

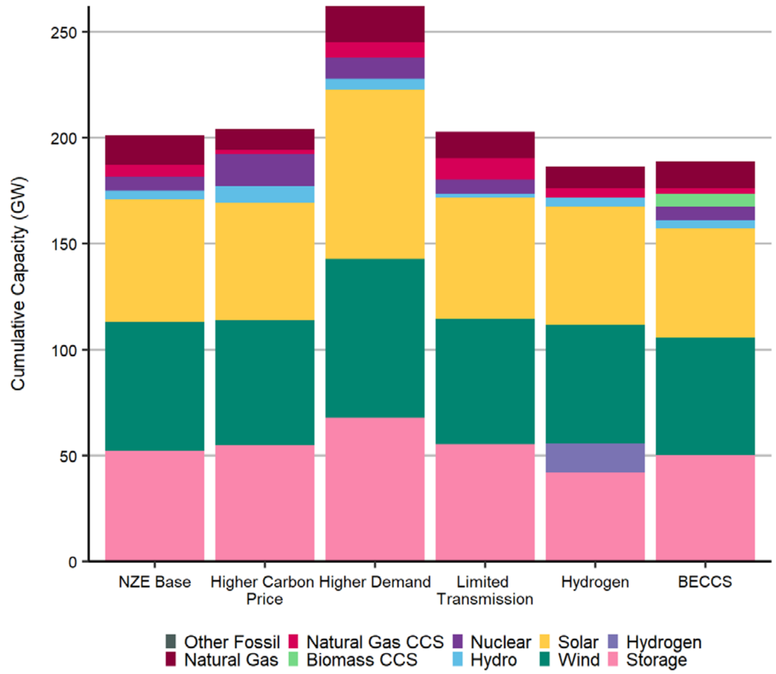
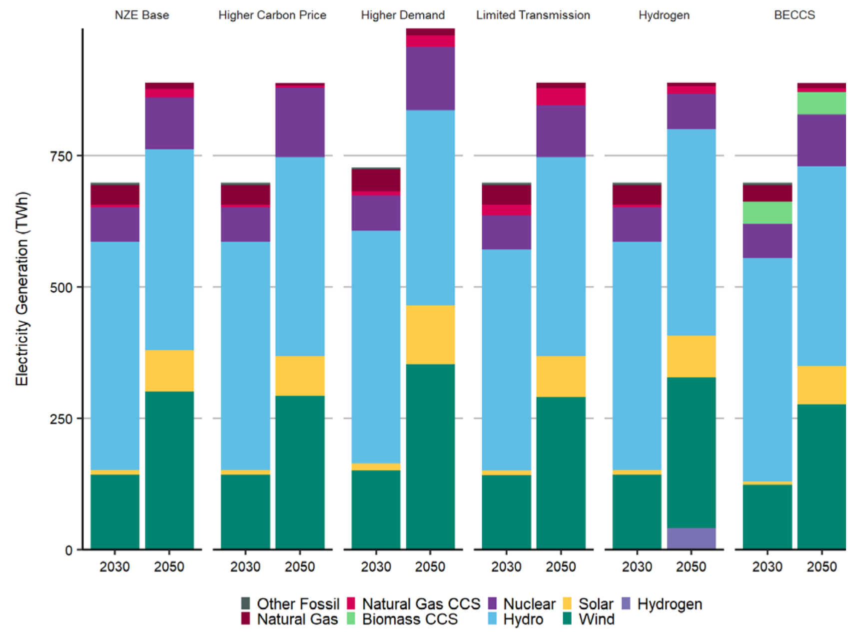


Figure NZ.6:
Electricity Generation by Technology in Different Scenarios



KEY TRENDS:

Electricity Supply in Alternative Net Zero Electricity Scenarios

- The Higher Carbon Price scenario increases nuclear and hydro but reduces natural gas generation, relative to the NZE Base scenario.
- The Limited Transmission scenario increases natural gas CCS generation in Alberta and Saskatchewan, relative to the NZE Base scenario.
- The BECCS scenario provides a technology pathway for economy wide GHG emissions reductions.
- Increased demand in the Higher Demand Scenario is mainly satisfied by solar, wind, and nuclear power.
- The Hydrogen scenario reduces the capacity and generation levels of all other low/zero-carbon emissions technologies except those of hydropower, relative to the NZE Base scenario.

Higher Carbon Price Scenario

In the Higher Carbon Price scenario, we see reductions in capacity and electricity generation by natural gas units in 2050 compared to the NZE Base scenario. Cumulative new natural gas capacity additions are 30% lower than NZE Base by 2050. Compared to NZE Base, natural gas-fired generation is 60% lower in 2050. Natural gas CCS is also impacted by the higher carbon price. Our assumption is that any residual CO_2 emissions that are not captured by the CCS process (10% of the combustion emissions) will see the full carbon price. Even though the carbon price only applies to this 10%, the higher carbon price increases the average cost of electricity produced by natural gas CCS by about 50% relative to the NZE Base scenario. That makes natural gas CCS less competitive. Compared to NZE Base, natural gas CCS cumulative capacity additions are 60% lower and electricity generation is 70% lower. The reductions in natural gas-fired generation capacity is offset by an increase in hydropower and nuclear SMR. Hydropower and SMR see a doubling of cumulative new capacity additions compared to the NZE Base scenario. Furthermore, this is the only scenario where we observe the addition of SMR units outside of Ontario and New Brunswick, with Alberta, Saskatchewan, and Nova Scotia seeing SMR additions.

Higher Demand Scenario

The Higher Demand scenario assumes a higher level of electrification and therefore about 12% higher electricity demand overall, or about 104 TWh in 2050. In 2050, the higher electricity demand in this scenario is satisfied by increased solar (+ 33 TWh), wind (+51 TWh), nuclear (+23 TWh), and natural gas CCS (+5 TWh) generation compared to NZE Base. Compared to the NZE Base scenario, those four technologies see a supply increase of 42%, 17%, 23%, and 31%, respectively. The installed storage capacity is 30% or about 16GW higher than NZE Base. The level of hydropower generation remains relatively unchanged.

Limited Transmission Scenario

The Limited Transmission scenario only sees notable changes in the four western provinces. In the NZE Base scenario the hydropower resources in B.C. and Manitoba partially provide system flexibility to manage variable wind and solar power supply in Alberta and Saskatchewan. This process is facilitated by the addition of new transmission capacity. The Limited Transmission scenario inhibits new transmission capacity additions and consequently the combined wind and solar power generation declines by about 5% relative to NZE Base. This reduction in generation is filled by a higher level of natural gas CCS units in Alberta and Saskatchewan. Compared to NZE Base, the Limited Transmission scenario sees a doubling of natural gas CCS capacity and generation.

Hydrogen Scenario

In many net-zero scenarios in previous studies,[46] low-carbon hydrogen plays an important role in many sectors, and hydrogen production increases. Our Hydrogen scenario assumes the existence of a relatively mature market for hydrogen in Canada, where hydrogen costs through electrolysis and natural gas with CCS have fallen significantly and supplies of low-carbon hydrogen are accessible for electricity producers. This supply of hydrogen is assumed to be exogenous to the producers, that is, they do not have to produce the hydrogen themselves, but purchase hydrogen at a delivered price, assumed to be about \$2020 US\$1.00/kg by 2050. We assume two hydrogen-fired generation technologies, hydrogen combined cycle and hydrogen simple cycle. In this scenario, we observe a cumulative hydrogen-fired generation capacity addition of 13 GW. Hydrogen technologies impact other technologies in a complex manner.

Under the assumed conditions, hydrogen technologies have lower overall economic costs compared to all natural gas technologies. Consequently, we see a 25% reduction in 2050 of non-CCS natural gas capacity (i.e., combined cycle and simple cycle) compared to NZE Base. Furthermore, the GHG emissions intensity of hydrogen combined cycle technology is lower than natural gas CCS. Therefore, natural gas CCS sees a 20% capacity reduction in 2050 compared to NZE Base.

[46] For example, the IEA's Net Zero by 2050 report projects the hydrogen-based fuel in the global energy mix to grow from about 90 Mt in 2020 to 530 MT in 2050. According to the IEA about 100 MT of hydrogen will be used to produce electricity in 2050, where currently the contribution of hydrogen for electricity generation is negligible.

The Hydrogen scenario also sees a 10% reduction in wind and solar capacity relative to NZE Base in 2050. The overall economics of the use of hydrogen for electricity supply is more favorable than building wind, solar and the additional flexible capacity they necessitate to balance supply and demand. Similarly, hydrogen technologies are more competitive than nuclear under the assumed conditions in most of the analysis period. Therefore, no new nuclear growth is seen in this scenario. Hydropower capacity remains unchanged compared to NZE Base.

Finally, hydrogen units also displace 32% of the storage capacity in 2050 compared to NZE Base as hydrogen-fired generating technologies can partially satisfy the overall electric power system's flexible capacity requirements.

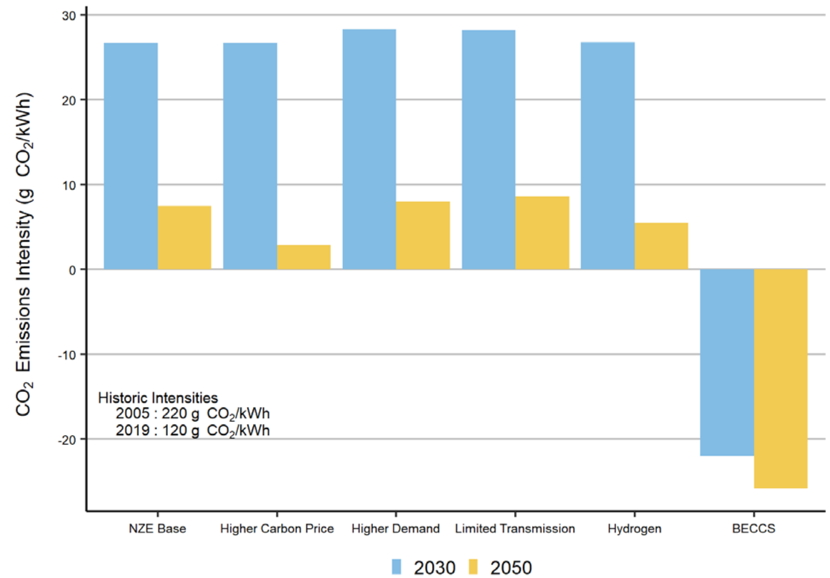
BECCS Scenario

The BECCS scenario assumes the availability of biomass CCS units for electricity generation in Alberta and Saskatchewan. Biomass CCS is considered to have negative GHG emissions, and we assume that the technology would get credit for carbon removal from the atmosphere. The credit is assumed to be calculated using the full carbon price. As the carbon price increases, biomass CCS units become a negative cost generation option, where its average cost of electricity in 2050 is -$85/MWh. Therefore, biomass CCS partially displaces all other generation technologies in Alberta and Saskatchewan. Relative to NZE Base, we estimate the resulting reduction in natural gas CCS generation in 2050 to be 56% and that of combined wind and solar to be about 15%.

The cumulative biomass CCS capacity addition by 2050 is 6 GW. Due to the limitations in available biomass resources, we assume this is the maximum possible biomass CCS capacity. At higher carbon prices, it may be economically competitive to import biomass for electricity production from other regions into Alberta and Saskatchewan, where CCS is viable. However, further analysis is required to verify this assumption.

Due to the carbon removal capability of biomass CCS, the electricity system in Canada becomes a net negative emissions economic sector in the BECCS scenario.

Figure NZ.7:
GHG Emissions Intensity of the Electricity Sector in Canada in Different Scenarios



GHG Emissions Intensity of Electricity Sector in Canada

Figure NZ.7 shows the GHG emissions intensity of the electricity sector in Canada in 2030 and 2050 in all scenarios we considered, compared to 2005 and 2019 levels.

In all scenarios, except the BECCS scenario, the GHG emissions intensity of Canada's electricity sector reaches about 27 grams of carbon dioxide equivalent per kilowatt-hour (gCO_2/kWh) in 2030. The value is 78% lower than the electricity sector emissions intensity in 2019. The emissions intensity further reduces in 2050 but varies across scenarios. The NZE Base scenario emissions intensity in 2050 is $8gCO_2/kWh$, a 93% reduction compared to the emissions intensity in 2005. The Higher Carbon Price scenario sees the 2050 emissions intensity declining to $3gCO_2/kWh$. While significant emissions reductions are achieved, none of the scenarios, except BECCS, see the overall electricity sector reaching net-zero.

Almost all of the remaining emissions come from natural gas-fired conventional units, which generate electricity infrequently, and uncaptured emissions from natural gas CCS units. Blending renewable natural gas with natural gas could potentially further reduce the small amount of remaining emissions in the sector, or provide a pathway for negative emissions if coupled with CCS. However, we have not assessed the potential of renewable natural gas to decarbonize Canada's electricity sector in this analysis.

The BECCS scenario sees the emissions intensity of the electricity sector going net negative, through carbon removal by the biomass CCS units. This would provide some emissions allowances for other economic sectors in Canada's path towards a net-zero future.

The electricity sector could play an important role in achieving deeper emissions reductions in Canada's energy system, both by reducing emissions from generating electricity and by reducing emissions in other sectors by electrification. Our analysis shows that there are many technological pathways to achieve significant emission reductions in the electricity sector. The majority of technologies required are available today, and Canadian electric utilities have experience in building and operating them. In Canada's pathway towards a net-zero future, the country's electricity sector will have multiple roles, including the supply of energy and potentially carbon removal through investing in negative emissions technologies.

KEY UNCERTAINTIES:
Net-Zero Electricity Results

Economics: The results and trends presented in this section are driven by the economic assumptions made on capital and operating costs of generating technologies, storage, and transmission lines. Any changes to our assumptions, particularly the ones made for variable renewables and storage, could potentially alter the results.

Policy Assumptions: The analysis makes hypothetical carbon pricing assumptions. The level of stringency and mechanisms of the carbon pricing system could potentially change the results.

Transmission System Representation: The current analysis does not model intra-provincial transmission systems. A need for significant increases in intra-provincial transmission in a given scenario can vary the results.

Demand profile: The demand profiles (i.e., how electricity demand changes over different time periods) used are constructed using historic observations. Changes to end-use energy demand, particularly under higher electrification, could impact the results.

Technology Representation: The analysis models only a limited number of generation technologies. Several other zero/low emissions technologies as well as grid management options such as demand side management exist. The inclusion of them could potentially change the comparative results.

Access and Explore Energy Futures Data

Datasets related to EF2021:

- **Figure Data:** Download the EF2021 figure data [EXCEL 365 KB]
- **Data Appendix:** The Energy Futures Data Appendix has customizable, downloadable tables arranged by variable (macroeconomic drivers, end-use demand, crude oil production, etc.) and publication year.
- **Machine Readable Files:** Looking to download all of the EF2021 data at once? It is available on Open Government.

Energy Futures Fact Sheets

- Deep dive into the projections with more detailed datasets, including monthly projections for:

  EF2021 Overview | Electricity | Energy Demand | Conventional Oil | Natural Gas | Natural Gas Liquids | Oil Sands

Explore Energy Futures – Interactive Data Visualization

Explore Canada's Energy Future with an interactive tool that allows users to visualize, download, and share the data behind long-term energy outlooks.

Student Resources

In partnership with Ingenium, the CER developed educational activities based on Canada's forecasted energy demand and supply.

Targeted at students between the grades of 9 and 11, the activities encourage students and educators to explore Canada's energy ecosystem using an interactive tool. This tool allows users explore how the future of energy in Canada over the long term. The material and student resources are available here.

Data Science with Open Data

Partnered with Fireside Analytics, this course is an introduction to Data Science with Open Data sets and R Studio. Learners will learn common buzzwords used in Data Science and will do hands-on labs visualizing and analyzing Open Data from the Canada's Energy Future series. This course is designed for learners who are new to computer programming and data science.

About the Canada Energy Regulator

The Canada Energy Regulator (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 the Indigenous peoples of Canada. 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
- Imports, Exports & Energy Markets – Imports and exports of certain energy products; monitoring aspects of energy supply, demand, production, development and trade.
- Exploration & production – Oil and gas exploration and production activities in the offshore and on frontier lands not covered by an accord.
- Offshore renewables – Offshore renewable projects and offshore power lines.

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, powerlines, and other energy infrastructure.
- Broader and deeper collaboration with stakeholders and partners informs our energy information.

About this Report

The CER's Energy Information core responsibility is closely linked to its mandate and responsibilities under the Canadian Energy Regulator Act (Act), which includes advising and reporting on energy matters. As well, under Part 7 of the Act, the CER regulates the export and import of natural gas and the export of natural gas liquids, crude oil and petroleum products, and electricity. The CER must ensure that, if authorized, oil and gas exports are surplus to Canadian requirements. The CER's monitoring of energy markets and assessments of Canadian energy requirements and trends helps support the discharge of its regulatory responsibilities. This report, Canada's Energy Future 2021: Energy Supply and Demand Projections to 2050, is the continuation of the Canada's Energy Future series, and projects long-term Canadian energy supply and demand trends.

EF2021 was prepared by CER technical staff under the direction of:

Bryce van Sluys
Director, Energy Outlooks
Bryce.vanSluys@cer-rec.gc.ca

Matthew Hansen
Technical Leader – Energy Futures
Matthew.Hansen@cer-rec.gc.ca

Andrea Oslanski
Project Manager – Energy Futures
Andrea.Oslanski@cer-rec.gc.ca

Calen Henry
Project Manager – Energy Futures
Calen.Henry@cer-rec.gc.ca

Specific questions about the information in this report may be directed to:

Key Drivers and Macroeconomics

Matthew Hansen
Matthew.Hansen@cer-rec.gc.ca

Energy Demand

Aaron Hoyle
Aaron.Hoyle@cer-rec.gc.ca

Matthew Hansen
Matthew.Hansen@cer-rec.gc.ca

Crude Oil

Peter Budgell
Peter.Budgell@cer-rec.gc.ca

Ryan Safton
Ryan.Safton@cer-rec.gc.ca

Natural Gas and NGLs

Melanie Stogran
Melanie.Stogran@cer-rec.gc.ca

Electricity

Michael Nadew
Michael.Nadew@cer-rec.gc.ca

Ganesh Doluweera
Ganesh.Doluweera@cer-rec.gc.ca

Climate Policy

Aaron Hoyle
Aaron.Hoyle@cer-rec.gc.ca

Matthew Hansen
Matthew.Hansen@cer-rec.gc.ca

General Questions

energyfutures@cer-rec.gc.ca

If a party wishes to rely on material from this report in any regulatory proceeding before the CER, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material.

Appendix 1:

Domestic Climate Policy Assumptions

This appendix reviews the domestic climate policy assumptions included in the Evolving Policies Scenario and the Current Policies Scenario. The Current Policies Scenario includes only domestic policies currently in place. The Evolving Policies Scenario assumes greater policy action over time, at roughly the same pace as recent historical policy implementation. It does this by assuming a hypothetical suite of domestic policy initiatives that build upon current policies. Some Evolving Policies Scenario policies increase the stringency or coverage of Current Policies Scenario policies. In these cases, the Evolving Policies Scenario policy in question takes over from the Current Policies Scenario policy. For example, in the Evolving Policies Scenario Canada's carbon pricing increases from the Current Policies Scenario schedule of $170/t by 2030 to $470/t by 2050.

In addition to extending Current Policies Scenario policies, the Evolving Policies Scenario also includes support for technologies that currently have limited commercial application. This means that these technologies see greater adoption through our Evolving Policies Scenario projection compared to the Current Policies Scenario, without adoption necessarily being explicitly driven by a particular policy. Examples include high-efficiency natural gas heat pumps for buildings, hydrogen fuel cells for heavy trucking and industry, utility scale battery storage, electrification and efficiency improvements in the industrial sector, and reduced emission intensity of oil and gas production.

Policy inclusion criteria for the Current Policies Scenario

The Current Policies Scenario includes energy and climate policies that were expected to be implemented in Canada at the time of analysis. To determine whether a policy was included in the analysis we applied the following criteria:

- the policy was publicly announced by 1 August 2021;
- there was sufficient information available to model the policy; and
- the policy was expected to significantly change our energy system projections.

Policy inclusion criteria for the Evolving Policies Scenario

The Evolving Policies Scenario includes all Current Policies Scenario policies. It adds to these a hypothetical suite of future policy developments, which aim to approximate "greater policy action over time, at roughly the same pace as recent historical policy implementation." Hypothetical Evolving Policies Scenario policies are designed based on the following premises:

- Announced policies that are being developed are included to the extent possible. Simplifying assumptions are made as required by a lack of regulatory detail.
- The types of hypothetical future policies that are modelled have historical precedent in those implemented by federal, provincial, or municipal governments.
- Policies gradually strengthen over time, as opposed to a concentration of policy development at a given time.

Table A1.1 provides an overview of the major policies included in the Current Policies and Evolving Policies Scenarios. All dollar values are given in nominal terms, unless otherwise stated.

Table A1.1

Overview of Domestic Climate Policies and EF2021 Assumptions[47]

Region	Policy or Strategy	Description	Assumption in EF2021 *Evolving and Current Policies scenarios unless otherwise noted*
Federal	Backstop Carbon Pricing	Applies a regulatory charge on fossil fuels at the end-use level. Industrial sectors that qualify for the Output Based Carbon Pricing System are exempt from fuel charge.	The fuel charge rises from $30/t in 2020 to $50/t CO_2e by 2022, then to 170$/t by 2030. **Current Policies:** The fuel charge is constant from 2030 to 2050. **Evolving Policies:** The fuel charge increases $15/t annually from 2030 to 2050, rising to 470$/t by 2050.
Federal	Output Based Carbon Pricing System	A performance-based carbon pricing system for industrial facilities. Applies a regulatory charge to industrial sectors based on their emissions intensity of output.	**Current Policies:** Most industrial sectors are required to reduce their emissions intensity of output by 20% relative to their 2014 to 2016 average from 2020 to 2050. The backstop carbon price is applied to residual emissions. **Evolving Policies:** Most industrial sectors are required to reduce their emissions intensity of output by 20% relative to their 2014 to 2016 average from 2020 to 2050, which then declines by 2% annually until 2050. The backstop carbon price is applied to residual emissions.
Federal	Phase out of coal-fired generation of electricity	A carbon intensity performance standard for coal-fired power plants.	Limits emissions intensity of existing coal-fired electricity generation to 370 CO_2e/GWh by 2030. No new coal-fired power plants are built.
Federal	Methane Regulations for the Upstream Oil and Gas Sector	Oil and gas facilities are required to adopt minimum standards for methane control technologies.	A minimum methane control technology is required to take market share from 2020 to 2030.
Federal	Zero emission passenger vehicle incentives	Market shares are adjusted to account for zero-emission passenger vehicles for federal policies.	Major policies include the iZev subsidy program, funding for charging network initiatives and tax write-offs for businesses. Quebec and B.C.'s zero emission vehicle mandates are modelled separately (described below). **Evolving Policies:** Zero emissions passenger vehicle new sales reach 100% by 2035. Remote communities and the territories are assumed to be exempt. Given that a federal mandate or regulation to reach 100% ZEV sales does not currently exist, we make several simplifying assumptions: ZEVs are available to meet Canadian demands, Canadian demands for vehicle types (such as car vs trucks/SUVs) are similar to current levels, ZEV adoption accelerates as we approach 2035, and increased deployment of electric vehicle infrastructure underlies ZEV adoption.
Federal	Northern REACHE Program	Program to reduce diesel use for electricity and heat in remote communities.	Increased market share for alternative technologies.
Federal	Energy Efficiency Regulations	Minimum energy efficiency standards for energy using technologies in the residential, commercial, and industrial sectors (e.g. space conditioning equipment, water heaters, household appliances, lighting).	Includes Amendment 16 to the Energy Efficiency Regulations. Major standards include minimum fuel utilization efficiencies for natural gas furnaces, a minimum energy factor for gas water heaters and ban of incandescent light bulbs. **Evolving Policies:** Includes Amendment 17 to the Energy Efficiency Regulations. Major standards include increasing the energy efficiency performance of home appliances, in addition to commercial space conditioners.

[47] For an exhaustive review of climate measures in Canada, see Environment and Climate Change Canada's Fourth Biennial Report on Climate Change, and Canada's revised NDC

Region	Policy or Strategy	Description	Assumption in EF2021 *Evolving and Current Policies scenarios unless otherwise noted*
Federal	Light-duty vehicle GHG emissions standards	New passenger vehicles and light-commercial vehicles/light trucks sold in Canada must meet progressively more stringent GHG emission standards.	**Current Policies:** We assume the fuel economy of new passenger cars and light trucks improves by 5% annually from 2022 to 2030, driven by increasing standards which will be aligned with the U.S. Environmental Protection Agency and currently under development. From 2031 to 2050 fuel economy improves by 2% per year for both passenger cars and light trucks. **Evolving Policies:** The fuel economy of new passenger cars and light trucks improves by 5% annually from 2020 to 2050. The fuel economy of new light trucks improves by 5% per year from 2022 to 2030, and 3.5% from 2031 to 2050.
Federal	Heavy-duty vehicle GHG emissions standards	New heavy duty vehicles sold in Canada must meet progressively more stringent GHG emissions standards.	**Current Policies:** We assume the fuel economy of new heavy duty vehicles improves by 2.25% per year from 2020 to 2030, driven by more stringent standards that require improvement covering up to model year 2027. Improvement slows over the later decades to 0.5% from 2031 to 2050. **Evolving Policies:** The fuel economy of new heavy duty vehicles improves by 2.25% per year from 2020 to 2050.
Federal	Clean Fuel Standard	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. carbon capture and storage).	**Current Policies:** Carbon intensity decrease of 12gCO_2e/MJ below 2016 levels by 2030. **Evolving Policies:** Continues same rate of decrease (about 1.2g CO_2e/MJ) from 2031 to 2050. Increased renewable natural gas blending, incentivized by credit creation mechanism.
Federal	Small Modular Reactor (SMR) Action Plan	Plan for the development, demonstration, and deployment of SMRs for multiple applications.	**Evolving Policies:** Assumes SMR development in Ontario and New Brunswick.
Federal	National energy code for buildings	Sets out technical requirements for the energy efficient design and construction of new buildings.	Assumes that the 2017 building code applies throughout the projection period, with marginal efficiency improvements to building shells and space conditioning. Evolving Policies: Assumes that new buildings are "net-zero energy ready" by 2030 across provinces and territories by substantially increasing the efficiency of building shells and space conditioning technologies.
Federal	Renewable Fuels Regulations	Minimum renewable fuel content for all regions except for Newfoundland and Labrador, and the Territories.	Specifies a minimum renewable fuel content of 5% for gasoline and 2% for diesel fuel sold in Canada by volume.
British Columbia	Zero- emissions vehicle mandate and incentives	Requires automakers to sell a minimum share of zero- or low- emission vehicles in addition to government-funded purchase subsidies and charging network incentives.	Follows the zero-emission vehicles act; Achieves 10% light duty zero-emission vehicles sales by 2025, 30% by 2030, and 100% by 2040.
British Columbia	CleanBC Better Homes and Better Buildings programs	Incentives for residential and commercial building efficiency improvements.	Rebates for switching to high-efficiency space and heating equipment, and building shells. Includes $3,000 rebate for types of residential heat pumps if switching from fossil fuel heating.
British Columbia	CleanBC industrial electrification		Electrification of planned natural gas production in the Peace region. **Evolving Policies:** Increased electrification of other industrial sectors.

Region	Policy or Strategy	Description	Assumption in EF2021 *Evolving and Current Policies scenarios unless otherwise noted*
British Columbia	CleanBC Industry Fund	Government investment in greenhouse gas-reducing projects and clean technologies.	Gradual market adoption of near-commercial clean industrial technologies.
British Columbia	Clean Energy Amendment Act	Sets a minimum percentage of electricity generation that must be provided by non-fossil fuels.	100% of provincial electricity generation must be provided by renewable or "clean" sources by 2025.
British Columbia	Energy Efficiency Act	Sets energy efficiency performance standards for energy using technologies.	Minimum energy efficiencies for household appliances, heating and cooling systems, lighting, industrial equipment.
British Columbia	Renewable Fuel Regulation	A minimum renewable fuel content for gasoline and diesel fuel.	5% ethanol content in gasoline, 4% biodiesel content in diesel
British Columbia	Low Carbon Fuel Standard	Requires a decrease in average carbon intensity of transport fossil through several compliance pathways.	Decrease in average carbon intensity of transport fossil fuels by 20% in 2030 relative to 2010.
British Columbia	Renewable Natural Gas Regulation	Requires that a portion of natural gas consumption be renewable natural gas by 2030.	Requires that 15% of natural gas consumption be provided by renewable natural gas by 2030. **Evolving Policies:** Renewable natural gas consumption increases to 20% by 2050.
Alberta	Technology Innovation and Emissions Reduction (TIER) Regulation	Carbon pricing system for large industrial emitters. Emitters pay a carbon price if they fail to meet the required emissions intensity reductions, and can earn credits if they surpass their required reductions.	Oil sands producer's emissions intensity benchmarks are the maximum of facility specific benchmarks (these decline 1% annually), or TIER "high performance" benchmarks from 2020 to 2030. Benchmarks remain at 2030 levels from 2031 to 2050. Evolving: Emissions intensity benchmarks decline at 2% relative to 2020 levels from 2031 to 2050.
Alberta	Renewable Fuels Standard	Requires renewable fuels to be blended into gasoline and diesel fuel.	5% ethanol content of gasoline, 2% biodiesel content of diesel.
Alberta	Methane Emissions Reduction Regulation	Requires the reduction of methane emissions from oil and gas operations by 45% by 2025 relative to 2014 levels.	A minimum methane control technology is required to take market share from 2020 to 2030.
Saskatchewan	Boundary Dam Carbon Capture Project	This project stores and captures CO_2 emissions from a 115MW coal plant	CCS projections account for the project.
Saskatchewan	Ethanol Fuel Act and Renewable Diesel Act.	Requires renewable fuels to be blended into gasoline and diesel fuel	7.5% ethanol content of gasoline, 2% biodiesel content of diesel.

Region	Policy or Strategy	Description	Assumption in EF2021 *Evolving and Current Policies scenarios unless otherwise noted*
Saskatchewan	Methane Action Plan	Requires a reduction in methane emissions from oil and gas extraction by 40 to 45% of 2015 levels	A minimum methane control technology is required to take market share from 2020 to 2030.
Manitoba	Strengthened Biofuels Act	Requires renewable fuels to be blended into gasoline and diesel.	Minimum of 10% ethanol in gasoline, and 5% biodiesel in diesel.
Manitoba	Efficiency Manitoba Act	Provides consumers with rebates and other incentives.	Includes lighting, space conditioning, and building shell rebates across residential, commercial, and some industrial sectors.
Manitoba	Green Energy Equipment tax credit	Tax credit for residential and commercial geothermal heat pumps.	15% tax credit.
Ontario	Strengthened Greener Gasoline Regulation and Greener Diesel Regulation (O Reg 97/14)	Requires renewable fuels to be blended into gasoline and diesel.	Requires 15% ethanol blending in gasoline by 2030and 4% biodiesel blending in diesel by 2020.
Quebec	Roulez vert program	Incentives for electric vehicles and charging station installations.	Rebates include $8,000 for new vehicles and $600 for home charging stations.
Quebec	Zero-emissions vehicle standard	Requires automakers to sell a minimum share of zero- or low-emission passenger vehicles via a credit market.	Credit target increases gradually to reach 22% by 2025. **Evolving:** Credit target increases to 100% zero-emissions vehicle new sales by 2035.
Quebec	Renewable Natural Gas Mandate	Requires that a portion of natural gas consumption be renewable natural gas.	1% of total by 2020 and 5% of total by 2025. **Evolving:** Increases gradually to 20% by 2050.
Quebec	Chauffez Vert program	Rebates for residential renewable energy space or water heating systems, if replacing fossil fuel system.	$1,275 for light fuel oil system replacements, $850 for propane system replacements.
New Brunswick	Renewable Portfolio Standard	Requires a minimum share of in-province electricity sales to be generated by renewable sources by 2020.	Minimum share is set to 40%. Imports from other jurisdictions and energy efficiency improvements qualify for compliance.
New Brunswick	Energy Efficiency Programs	Provides purchase incentives for energy efficient appliances in residential, commercial, and industrial sectors	Various rebates for approved technologies

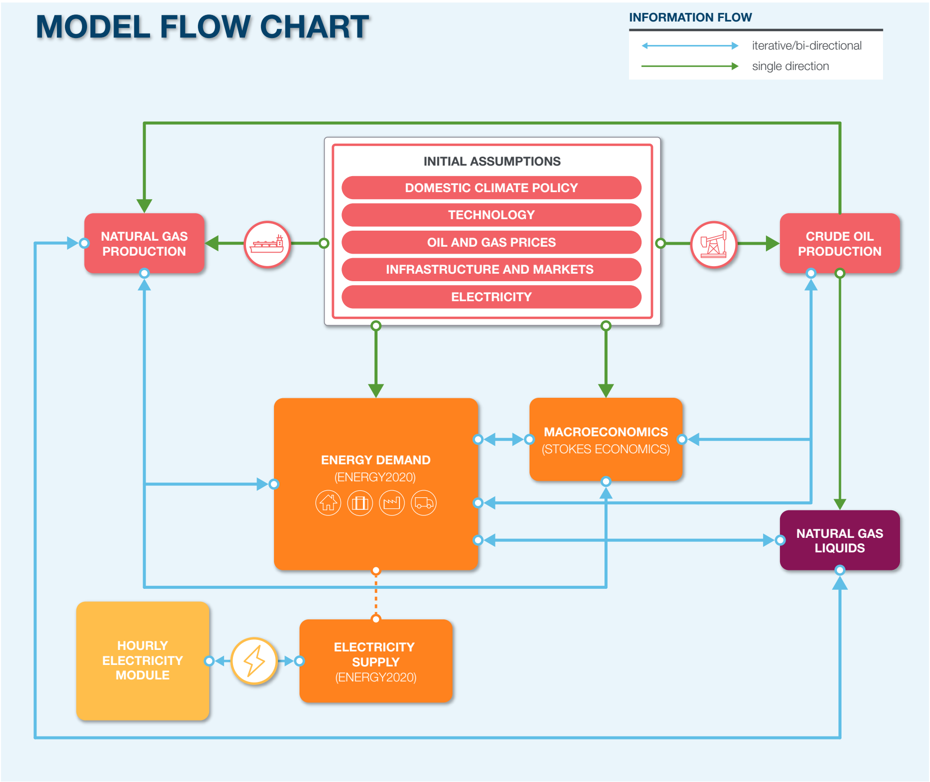
Region	Policy or Strategy	Description	Assumption in EF2021 *Evolving and Current Policies scenarios unless otherwise noted*
Nova Scotia	Electricity Generation GHG emissions cap.	Requires declining GHG emissions from in-province electricity generators.	Requires emissions from the electricity sector to decline to 4.5Mt by 2030.
Nova Scotia	Renewable Electricity Regulations	Requires a minimum percentage of electricity consumption be provided by renewable resources.	Set at 40% by 2020.
Nova Scotia	Maritime Link	High-voltage transmissions line that will connect Nova Scotia to the Muskrat Falls hydroelectric project in Newfoundland.	Included.
Nova Scotia	EfficiencyNS Programs	Incentives for residential, commercial, and some industrial sectors.	Included.
Newfoundland	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.
Prince Edward Island	EfficiencyPEI Rebates	Incentives for residential, commercial, and some industrial sectors.	Various rebates on energy efficient appliances, such as heat pumps, solar systems, biomass heating, and fuel-efficient furnaces.
Northwest Territories	2030 Energy Strategy	Measures that aim to support low-carbon energy for transportation and space heating. Incentives for energy efficiency and conservation.	Key measures include: 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, rebates for zero and low emissions vehicles.
Yukon	Our Clean Future	Various measures that aim to reduce greenhouse gas emissions.	Key measures include: 10% zero emissions vehicles new sales by 2025 and 30% by 2030, zero-emission vehicles rebates, blending of renewable fuels into diesel and gasoline, energy efficiency incentives and regulations, and renewable energy projects for remote communities.

Appendix 2:

Overview of the Energy Futures Modeling System

Energy Futures includes a wide range of projections for Canadian energy supply and demand. These projections are the result of a modeling system consisting of several interactive components (or modules) which produce future Canadian energy trends. Figure A2.1 outlines the system in a diagram.

Figure A2.1:
Energy Futures Modelling Framework Flow Chart



In EF2021, the full Energy Futures Modeling System is used to create projections for the Evolving and Current Policies Scenarios. The six Towards Net-Zero electricity scenarios were modeled using the hourly electricity module.

Overview of Model Components

Initial Assumptions: The starting point for Energy Futures analysis is the development of initial assumptions on various aspects of the global and Canadian energy system. Benchmark crude oil and natural gas price assumptions are based on a survey of projections by other forecasting agencies like the IEA and the U.S. Energy Information Administration, complemented by internal analysis. It is important to note that these assumptions are not predictions of future crude oil and natural gas prices, but necessary inputs for the analytical process. Other starting assumptions include energy and climate policies and programs, scenario details such as technology fuel pathways, and volumes of LNG exports.

Oil Production: This module 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, and non-oil sands deliverability module for western Canada, and analysis of other regions in Canada.

Gas Production: This module estimates the production of natural gas throughout Canada. The module relies upon oil and natural gas price assumptions, LNG export assumptions, as well as a crude oil production estimated from the oil supply module and other factors such as 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).

Macroeconomics: Macroeconomic projections for each of the scenarios were provided by Stokes Economic Consulting Inc. Stokes developed unique projections of key macroeconomic indicators such as GDP, exchange rate, and industry gross output for each of the scenarios, based on the price assumptions and output of the CER's supply and demand models.

Demand: The demand projections are developed using ENERGY2020: a detailed energy model created by Systematic Solutions Incorporated. It creates projections for energy demand and electricity generation based on historical energy data and, where needed, assumed future trends for parameters such as supply, demand, economic growth, efficiency, prices, and investment.

Electricity: The electricity projections are developed using ENERGY2020: a detailed energy model created by Systematic Solutions Incorporated. It creates projections for energy demand and electricity generation based on historical energy data, and where needed, assumed future trends for parameters such as supply, demand, economic growth, efficiency, prices, and investment. The ENERGY2020 projections are guided by the hourly electricity module, which provides increased temporal granularity which is important for analyzing how the system responds to increasing levels of variable renewable energy, storage, and transmission.

Natural Gas Liquids: This module provides estimates of NGL supply and demand in Canada. The module simulates various categories of liquids: ethane, butane, propane, condensate and pentane plus. For each liquid, the module provides estimates of production, supply and demand at the individual provincial/territorial level.

www.cer-rec.gc.ca/energyfutures